YEAR 2001

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ANNUAL REPORT
OF

NorthWestern Energy, L.L.C

GAS UTILITY

TO THE
PUBLIC SERVICE COMMISSION
STATE OF MONTANA
1701 PROSPECT AVENUE
P.O. BOX 202601
HELENA, MT 59620-2601

REVISED JULY 28, 1998

NATURAL GAS ANNUAL REPORT

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Sch. 1

IDENTIFICATION

Legal Name of Respondent:	NorthWestern Energy, L.L.C. (formerly The Montana Power Company)
Name Under Which Respondent Does Business:	NorthWestern Energy, L.L.C.
Date Utility Service First Offered in Montana:	Electricity - Dec 12, 1912 Natural Gas - Jan 01, 1933 Propane - Oct 13, 1995
Person Responsible for Report:	E. J. Kindt
Telephone Number for Report Inquiries:	(406) 497-2233
Address for Correspondence Concerning Report:	40 East Broadway Butte, Montana 59701

If direct control over respondent is held by another entity, provide below the name, address, means by which control is held and percent ownership of controlling entity.

NorthWestern Corporation
125 South Dakota Avenue
Sioux Falls, SD 57104-6403

Sch. 2	BOARD OF DIRECTORS	
	Director's Name & Address (City, State)	Remuneration
1		
2	NOT APPLICABLE	
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Sch. 3

OFFICERS

Title	Department Supervised	Name
President	Executive	John D. Haffey
Vice President, Human Resources and Administration	Human Resources	Pamela K. Merrell
Vice President, Treasurer and Chief Financial Officer	Treasury Services	Ellen M. Senechal
Vice President and Chief Accounting Officer	Controller Services	Ernie J. Kindt
Vice President and Chief Information Officer	Information Services	David N. Ottolino
Vice President and General Counsel	Legal Services	Michael P. Manion
Vice President, Energy Supply	Energy Supply	William A. Pascoe
Vice President, Transmission and Distribution Services	Transmission and Disbribution Services	David A. Johnson
Vice President, Regulatory Affairs	Regulatory Affairs	Patrick R. Corcoran

Sch. 4

CORPORATE STRUCTURE - 1/

Subsidiary/Company Name	Line of Business	Earnings (000)	% of Total
NORTHWESTERN ENERGY, L.L.C.			
Utility Operations		($46,677)	99.81%
Electric Utility	Electric utility		
Natural Gas Utility	Natural gas utility		
Canadian-Montana Pipe Line Corporation	Natural gas transmission		
Colstrip Community Services Company	Inactive		
Montana Power Capital 1	Financing		
MPC Natural Gas Funding Trust	Bond transition financing		
Nonutility Operations		(91)	0.19%
Montana Power Services Company	Inactive		
Discovery Energy Solutions, Inc.	Energy services consulting		
One Call Locators, Ltd.	Underground facility locating		
Colstrip Unit 4 Lease Mgmt Division	Wholesale sales of electric power *		
TOTAL		($46,768)	100.00%

1/ - This schedule is prepared as of the filing date of 4/30/02. The balance sheet is prepared as of 12/31/01, and thus discloses investments in subsidiary companies not reflected on this schedule.

* Colstrip Unit 4 Lease Management Division is an operating division of Northwestern Energy L.L.C.

Sch. 5

CORPORATE ALLOCATIONS

Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Corporate - 1/	Includes the following departments: CEO; CFO; Vice Pres. & General Counsel; Investor Services; Strategic Planning; Corp. & Shareholder Services; Business Development; Government Affairs-Federal	All overhead costs not charged directly are allocated to the Utility & Nonutilities based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	$1,897,179	67.95%	$895,040
Utility Administration Executive Department	Includes the following departments: COO; MAP; Government Affairs-State	All overhead costs not charged directly are allocated to the Utility companies based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	1,178,906	91.36%	111,463
Human Resources	Includes the following departments: Benefits; Compensation & Labor Relations; Employment; Organizational Development; Payroll; Employee Relations; Consultant Services	All overhead costs not charged directly are allocated to the Utility companies based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	3,891,136	78.03%	1,095,858
Financial Accounting - 2/	Includes the following departments: Vice Pres. & CFO; Chief Accounting Officer; T&D Accounting; Tax & Financial Reporting; Treasury Services; Risk Management; Internal Auditing	All overhead costs not charged directly are allocated to the Utility companies based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	5,416,356	73.31%	1,971,460
Facilities	Includes the following departments: Facilities; Mailing Services; Records Control	All overhead costs not charged directly are allocated to the Utility companies based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	2,709,345	88.96%	336,212
Information Services	Includes the following departments: SAP Competency Center; Infrastructure Oper.; IS Architecture; Key Accounts Representative; Security; IS Support & Services; IS Administration	All overhead costs not charged directly are allocated to the Utility companies based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	9,331,352	86.17%	1,497,485

Sch. 5

CORPORATE ALLOCATIONS

Departments Allocated	Description of Services	Allocation Method	$ to MT El & Gas Utilities	MT %	$ to Other
Legal Services - 2/	Includes the following departments: Legal Services	All overhead costs not charged directly are allocated to the Utility companies based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	583,797	45.92%	687,505
Corporate Communications & Advertising - 2/	Includes the following departments: Corp. Advertising; Video/Photo Services; Web Services; Corp. Communications; Community Relations; Printing Services	All overhead costs not charged directly are allocated to the Utility companies based on number of employees or on %'s developed using formulas based on net plant, revenues and gross payroll.	2,979,528	77.11%	884,656
TOTAL			$27,987,599	78.91%	$7,479,679

1/ - After June 30, 2001, the allocated costs include only companies sold to NorthWestern Energy.

2/ - These departments continued to do work for Touch America and Corporate through 2001, however will go with NorthWestern Energy. The split of costs does not reflect future expectations.

Sch. 6

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED TO UTILITY

	Affiliate Name	Products & Services	Method to Determine Price	Charges to Utility	% of Total Affil. Revs.	Charges to MT Utility
1						
2	**Nonutility Subsidiaries**					
3	Western Energy Company	Coal sales & transportation	Contract Rates	($210,381)	-0.03%	($210,381)
4		Misc. Services	Actual Costs Incurred	64,456	0.01%	64,456
5	One Call Locators	Line location services	Market Rates	1,424,423	0.20%	1,424,423
6	Tetragenics	Engineering Services	Market Rates	384,346	0.05%	384,346
7	Touch America, Inc.	Communication Services	Market Rates	870,667	0.12%	870,667
8	Entech, Inc.	Interest on notes	Interest rate used is average of	1,797,902	0.25%	1,797,902
9			short term borrowing rates &			
10			available short term investment rates.			
11			2001 Annual Average Rate = 4.8965%			
12	Discovery Energy Solutions	Energy services consulting	Market Rates	4,038	0.00%	4,038
13	Continental Energy Services, Inc.	Interest on notes	Interest rate used is average of	538,561	0.08%	538,561
14			short term borrowing rates &			
15			available short term investment rates.			
16			2001 Annual Average Rate = 4.8965%			
17	Colstrip Unit 4 -	Purchased power	Market Rates	1,064,286	0.15%	1,064,286
18	Lease Management Division					
19						
20						
21	**Total Nonutility Subsidiaries**			5,938,298	0.83%	5,938,298
22	**Total Nonutility Subsidiaries Revenues**			714,119,000		
23	**Utility Subsidiaries**					
24						
25	**Total Utility Subsidiaries**					
26	**Total Utility Subsidiaries Revenues**			7,793,000		
27	**TOTAL AFFILIATE TRANSACTIONS**			$5,938,298		$5,938,298

Sch. 7

AFFILIATE TRANSACTIONS - PRODUCTS & SERVICES PROVIDED BY UTILITY

	Affiliate Name	Products & Services	Method to Determine Price	Charges to Affiliate	% of Total Affil. Exp.	Revenues to MT Utility
1						
2	**Nonutility Subsidiaries**					
3	Western Energy Company	Sales of Electricity	Tariff Schedules	$1,686,191	0.26%	$1,686,191
4						
5	Touch America, Inc.	Sales of Gas & Electricity	Tariff Schedules	135,004	0.02%	135,004
6						
7						
8						
9	**Total Nonutility Subsidiaries**			1,821,195	0.28%	1,821,195
10	**Total Nonutility Subsidiaries Expenses**			643,134,000		
11						
12						
13	**Utility Subsidiaries**					
14	Colstrip Community Services	Project Services	Actual Costs Incurred	-	0.00%	-
15	**Total Utility Subsidiaries**			-	0.00%	-
16	**Total Utility Subsidiaries Expenses**			601,083,000		
17	**TOTAL AFFILIATE TRANSACTIONS**			$1,821,195		$1,821,195

Sch. 8	MONTANA UTILITY INCOME STATEMENT - NATURAL GAS (INCLUDES CMP)					
	Account Number & Title	This Year Cons. Utility	Glacier Gas 1/	This Year Montana	Last Year Montana	% Change
1						
2	400 Operating Revenues	$138,935,331		$ 138,935,331	$ 120,230,631	15.56%
3						
4	**Total Operating Revenues**	138,935,331	-	138,935,331	120,230,631	15.56%
5						
6	**Operating Expenses**					
7						
8	401 Operation Expense	103,015,335		103,015,335	102,182,435	0.82%
9	402 Maintenance Expense	4,310,719		4,310,719	4,590,238	-6.09%
10	403 Depreciation Expense	9,796,160		9,796,160	8,438,876	16.08%
11	404-405 Amort. & Depletion of Gas Plant	1,160,428		1,160,428	327,088	254.78%
12	408.1 Taxes Other Than Income Taxes	13,602,503		13,602,503	14,165,985	-3.98%
13	409.1 Income Taxes-Federal	(2,098,249)		(2,098,249)	1,303,325	-260.99%
14	-Other	46,645		46,645	262,231	-82.21%
15	410.1 Deferred Income Taxes-Dr.	21,139,186		21,139,186	5,962,503	254.54%
16	411.1 Deferred Income Taxes-Cr.	(20,157,476)		(20,157,476)	(17,433,895)	-15.62%
17	411.4 Investment Tax Credit Adj.	(124,796)		(124,796)	(123,713)	-0.88%
18						
19	**Total Operating Expenses**	130,690,455	-	130,690,455	119,675,073	9.20%
20	**NET OPERATING INCOME**	$ 8,244,876	$ -	$ 8,244,876	$ 555,558	1384.07%
21						
22	1/ In July 2000, Glacier Gas Co.'s production assets were sold to the oil and natural gas operations of Entech					
23	and its pipeline assets were sold to a third party. In October 2000, Glacier Gas Co. was included in the sale of Entech's					
24	oil and natural businesses to PanCanadian.					
25						

Sch. 9	MONTANA REVENUES - NATURAL GAS (INCLUDES CMP)			
	Account Number & Title	This Year Cons. Utility	Last Year Montana	% Change
1				
2	**Core Distribution Business Units**			
3	**(DBUs)**			
4	440 Residential	$82,369,068	$69,806,882	18.00%
5	442.1 Commercial	39,244,620	30,965,854	26.74%
6	442.2 Industrial Firm	2,066,607	3,293,973	-37.26%
7	445 Public Authorities	216,710	123,664	75.24%
8	448 Interdepartmental Sales	301,647	387,754	-22.21%
9	491.2 CNG Station	13,105	10,624	23.36%
10				
11	**Total Sales to Core DBUs**	124,211,758	104,588,751	18.76%
12				
13	447 Sales for Resale	881,436	662,300	33.09%
14				
15	**Total Sales of Natural Gas**	881,436	662,300	33.09%
16				
17	**Transportation**			
18				
19	489 Transportation (inc. CMP)	9,126,413	12,628,796	-27.73%
20	495 Storage	2,432,834	2,507,240	-2.97%
21				
22	**Total Revenues From Transportation**	11,559,247	15,136,036	-23.63%
23				
24	**Other Operating Revenue**			
25				
26	Montana Power Company	2,282,890	(156,456)	1559.13%
27				
28	**Total Other Operating Revenue**	2,282,890	(156,456)	1559.13%
29	**TOTAL OPERATING REVENUE**	138,935,331	120,230,631	15.56%
30				
31				
32				
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34				

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1	**Production Expenses**			
2	**Production & Gathering-Operation**			
3	750 Supervision & Engineering	$0	$0	-
4	751 Maps & Records	-	-	-
5	752 Gas Wells Expenses	-	-	-
6	753 Field Lines Expenses	-	-	-
7	754 Field Compressor Station Expense	-	-	-
8	755 Field Comp. Station Fuel & Power	-	-	-
9	756 Field Meas. & Reg. Station Expense	-	-	-
10	757 Dehydration Expense	-	-	-
11	758 Gas Well Royalties	-	-	-
12	759 Other Expenses	-	-	-
13	760 Rents	-	-	-
14	**Total Oper.-Production & Gathering**	-	-	-
15				
16	**Other Gas Supply Expense-Operation**			
17	800 NG Wellhead Purchases	57,946,493	46,766,572	23.91%
18	800 NG Wellhead Purchases, Intraco.	-	-	-
19	803 NG Transmission Line Purchases	1,037,078	988,913	4.87%
20	805 Other Gas Purchases	21,073,548	(10,392,647)	302.77%
21	805 Purchased Gas Cost Adjustments	-	-	-
22	805 Incremental Gas Cost Adjustments			
23	805 Deferred Gas Cost Adjustments			
24	806 Exchange Gas			
25	807 Well Expenses-Purchased Gas	8,500	198,595	-95.72%
26	807 Purch. Gas Meas. Stations-Oper.	-	-	-
27	807 Purch. Gas Meas. Stations-Maint.	-	-	-
28	807 Purch. Gas Calculations Expenses	-	-	-
29	808 Other Purchased Gas Expenses	-	-	-
30	808 Gas Withdrawn from Storage -Dr.	29,726,001	8,454,544	251.60%
31	809 Gas Delivered to Storage -Cr.	(33,426,829)	(8,560,238)	-290.49%
32	810 Gas Used-Comp. Station Fuel-Cr.			
33	811 Gas Used-Products Extraction-Cr.			
34	812 Gas Used-Other Utility Oper.-Cr.			
35	813 Other Gas Supply Expenses		-	-
36	**Total Other Gas Supply Expenses**	76,364,790	37,455,739	103.88%
37	**Total Production Expenses**	76,364,790	37,455,739	103.88%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1	**Storage Expenses**			
2				
3	**Underground Storage-Operation**			
4	814 Supervision & Engineering	129,275	224,213	-42.34%
5	815 Maps & Records	2,615	35,084	-92.55%
6	816 Wells	138,489	81,877	69.14%
7	817 Lines	68,948	17,137	302.33%
8	818 Compressor Station	221,913	133,039	66.80%
9	819 Compressor Station Fuel & Power	-	3,899	-100.00%
10	820 Measuring & Regulating Station	32,761	22,497	45.62%
11	821 Purification	38,233	65,402	-41.54%
12	824 Other Expenses	131,360	76,461	71.80%
13	825 Storage Well Royalties	98,574	87,848	12.21%
14	826 Rents	-	14,443	-100.00%
15	**Total Operation-Underground Storage**	862,168	761,900	13.16%
16				
17	**Underground Storage-Maintenance**			
18	830 Supervision & Engineering	59	22,430	-99.74%
19	831 Structures & Improvements	23,118	32,357	-28.55%
20	832 Reservoirs & Wells	6,127	17,105	-64.18%
21	833 Lines	7,767	19,645	-60.46%
22	834 Compressor Station Equipment	120,297	72,556	65.80%
23	835 Meas. & Reg. Station Equipment	12,918	13,394	-3.55%
24	836 Purification Equipment	5,515	4,422	24.71%
25	837 Other Equipment	12,803	9,716	31.77%
26	**Total Maintenance-Underground Storage**	188,604	191,625	-1.58%
27	**Total Underground Storage Expenses**	1,050,773	953,525	10.20%
28	**Transmission Expenses**			
29	**Transmission-Operation**			
30	850 Supervision & Engineering	1,739,025	2,056,909	-15.45%
31	851 System Control & Load Dispatching	435,430	493,048	-11.69%
32	853 Compressor Station Labor & Expense	517,932	416,013	24.50%
33	855 Other Fuel & Power for Comp. Stat.	-	29,578	-100.00%
34	856 Mains	406,182	512,969	-20.82%
35	857 Measuring & Regulating Station	604,524	603,254	0.21%
36	858 Transmission & Comp.-By Others	-	29,673	-100.00%
37	859 Other Expenses	881,926	996,129	-11.46%
38	860 Rents	-	1,399	-100.00%
39	**Total Operation-Transmission**	4,585,019	5,138,972	-10.78%
40	**Transmission-Maintenance**			
41	861 Supervision & Engineering	394,767	482,643	-18.21%
42	862 Structures & Improvements	70,006	63,177	10.81%
43	863 Mains	532,514	577,934	-7.86%
44	864 Compressor Station Equipment	363,988	448,871	-18.91%
45	865 Meas. & Reg. Station Equipment	297,606	318,647	-6.60%
46	867 Other Equipment	7,296	14,951	-51.20%
47	**Total Maintenance-Transmission**	1,666,177	1,906,223	-12.59%
48	**Total Transmission Expenses**	6,251,197	7,045,194	-11.27%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1	**Distribution Expenses**			
2	**Distribution-Operation**			
3	870 Supervision & Engineering	611,238	434,832	40.57%
4	872 Compressor Station Labor & Expense	395	4,518	-91.26%
5	873 Compressor Station Fuel and Power	-	-	-
6	874 Mains and Services	1,362,893	982,215	38.76%
7	875 Meas. & Reg. Station-General	18,492	21,535	-14.13%
8	876 Meas. & Reg. Station-Industrial	2,374	2,999	-20.82%
9	877 Meas. & Reg. Station-City Gate	18,483	32,438	-43.02%
10	878 Meter & House Regulator	668,227	770,384	-13.26%
11	879 Customer Installations	2,294,153	2,830,064	-18.94%
12	880 Other Expenses	858,946	835,453	2.81%
13	881 Rents	13,446	13,957	-3.66%
14	**Total Operation-Distribution**	5,848,647	5,928,395	-1.35%
15	**Distribution-Maintenance**			
16	885 Supervision & Engineering	220,530	324,473	-32.03%
17	886 Structures & Improvements	10,977	16,941	-35.20%
18	887 Mains	692,471	788,259	-12.15%
19	889 Meas. & Reg. Station Exp.-General	112,117	76,894	45.81%
20	890 Meas. & Reg. Station Exp.-Industrial	2,327	3,493	-33.38%
21	891 Meas. & Reg. Station Exp.-City Gate	13,888	15,062	-7.80%
22	892 Services	320,928	454,337	-29.36%
23	893 Meters & House Regulators	331,384	281,138	17.87%
24	894 Other Equipment	12,909	22,624	-42.94%
25	**Total Maintenance-Distribution**	1,717,532	1,983,221	-13.40%
26	**Total Distribution Expenses**	7,566,179	7,911,616	-4.37%
27	**Customer Accounts Expenses**			
28	**Customer Accounts-Operation**			
29	901 Supervision	-	-	-
30	902 Meter Reading	408,812	303,842	34.55%
31	903 Customer Records & Collection	2,502,948	2,002,022	25.02%
32	904 Uncollectible Accounts	951,829	839,594	13.37%
33	905 Miscellaneous Customer Accounts	247	345	-28.57%
34	**Total Customer Accounts Expenses**	3,863,835	3,145,803	22.83%
35				
36	**Customer Service & Information Expenses**			
37	**Customer Service-Operation**			
38	907 Supervision	-	31,402	-100.00%
39	908 Customer Assistance	838,170	881,433	-4.91%
40	909 Inform. & Instructional Advertising	588,336	167,216	251.84%
41	910 Misc. Customer Service & Inform.	322	1,081	-70.18%
42	**Total Customer Service & Information Exp.**	1,426,828	1,081,132	31.98%
43				
44	**Sales Expenses**			
45	**Sales-Operation**			
46	911 Supervision	44,458	61,439	-27.64%
47	912 Demonstrating & Selling	316,064	293,819	7.57%
48	913 Advertising	13,895	172,385	-91.94%
49	916 Miscellaneous Sales	3,190	11,076	-71.20%
50	**Total Sales Expenses**	377,607	538,719	-29.91%

Sch. 10	MONTANA OPERATION & MAINTENANCE EXPENSES - NATURAL GAS (INCLUDES CMP)			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1	**Administrative & General Expenses**			
2	**Admin. & General - Operation**			
3	407 Amortization of Regulatory Asset	(7,394,901)	33,181,738	-122.29%
4	920 Administrative & General Salaries	8,936,927	6,716,530	33.06%
5	921 Employee Travel	242,982	348,129	-30.20%
6	921 Office Supplies & Expenses	1,244,239	1,161,338	7.14%
7	922 Administrative Exp. Transferred-Cr.	(905,947)	(994,079)	8.87%
8	923 Outside Services Employed	1,332,325	2,442,930	-45.46%
9	924 Property Insurance	198,271	11,530	1619.66%
10	925 Legal & Claim Department	1,571,400	720,818	118.00%
11	926 Employee Pensions & Benefits	1,046,285	(85,482)	1323.98%
12	928 Regulatory Commission Expenses	41,199	92,261	-55.34%
13	930 General Advertising	1,828	243,566	-99.25%
14	930 Miscellaneous General Expenses	332,640	629,386	-47.15%
15	930 USBC Expenses	1,468,423	1,391,578	5.52%
16	931 Rents	1,570,768	2,267,150	-30.72%
17	**Total Operation-Admin. & General**	9,686,441	48,127,393	-79.87%
18	**Admin. & General - Maintenance**			
19	935 General Plant	738,406	513,551	43.78%
20	**Total Admin. & General Expenses**	10,424,846	48,640,944	-78.57%
21	**TOTAL OPER. & MAINT. EXPENSES**	$107,326,054	106,772,673	0.52%
22				
23				
24				
25				
26				

Sch. 11	MONTANA TAXES OTHER THAN INCOME - NATURAL GAS (INCLUDES CMP)				
		Description	This Year	Last Year	% Change
1					
2		**Federal Taxes**			
3	2521xx	Social Security, Medicare and Unemployment	$1,706,540	$595,708	186.47%
4					
5		**Montana Taxes**			
6	252410	Real Estate & Personal Property	12,942,865	13,498,406	-4.12%
7	252213	Crow Tribe RR and Utility Tax	15,823	65,786	-75.95%
8	252450	Consumer Counsel	110,486	92,463	19.49%
9	252450	Public Service Commission	363,816	293,771	23.84%
10	252450	Production	0	16,491	-100.00%
11		Other Miscellaneous	7,413	55,922	-86.74%
12					
13		**District of Columbia Taxes**			
14	2521xx	Social Security, Medicare and Unemployment	48	72	-33.33%
15					
16		**Canadian Taxes**			
17		Ad Valorem	20,404	71,752	-71.56%
18					
19		**Other**			
20		Payroll Tax Credit	(1,564,893)	(524,386)	-198.42%
21					
22	**TOTAL TAXES OTHER THAN INCOME**		$13,602,503	$14,165,986	-3.98%

Sch. 12	PAYMENTS FOR SERVICES TO PERSONS OTHER THAN EMPLOYEES, 1/		
	Name of Recipient	Nature of Service	Total
1	Allen & Company, Inc.	Financial advisory services	$100,000
2	Alme Construction, Inc.	Gas Pipeline Construction	1,943,867
3	Anderson Tree Service	Tree trimming	483,491
4	Asplundh	Tree trimming	1,575,753
5	Bill Field Trucking, LLC	Equipment transportation	303,396
6	Buck Consultants, Inc.	Recordkeeper	125,281
7	Burns International Security	Security service	256,946
8	Cory Clarke	Engineering Services	105,995
9	Crowley, Haughey,Hanson	Legal services	293,857
10	Deloitte Consulting	Consulting	1,403,238
11	Dorsey & Whitney, LLP	Legal services	130,960
12	Express Services, Inc.	Temporary employment service	444,618
13	FX Drilling Company	Drilling Services	106,784
14	Georgeson Shareholder	Proxy statements	283,976
15	Goldman Sachs	Consulting	2,546,558
16	Gsea Montana	Advertising	391,864
17	Harp Line Constructors Co.	Line construction & maintenance	4,995,142
18	Heath Consultants, Inc.	Gas leak detection	148,892
19	Howrey & Simon	Environmental consulting	161,275
20	HR Link Group Inc.	Computer services	131,390
21	Hughes, Kellner, Sullivan & Alke	Legal services	136,206
22	IBEX Construction	Tree trimming	335,448
23	IBM Corp	Computer maintenance	1,181,633
24	Independent Inspection Co	Electric line inspection	1,052,371
25	Intergraph Public Safety	Software maintenance	125,337
26	Itron, Inc.	Hardware/software maintenance	309,774
27	Jensen's Tree Service, Inc.	Tree trimming	291,331
28	KM Construction	Contractor	115,619
29	Lewis Manufacturing & Construction	Construction	453,339
30	Mattingly Testing Services, Inc.	Inspection services	101,376
31	Merrill Communications, LLC	Printing services	757,581
32	Mike Boylan Excavating	Contractor	119,338
33	Mtn.Utility Constr.& Design	Contractor	7,665,512
34	Nat'l Ctr. For Appropriate Technology	Lab Testing	530,524
35	Natural Gas Services	Gas service work	185,544
36	Northwest Energy Efficiency	Energy serices	456,969
37	Olson Land Services	Right of way	111,415
38	Orcom Solutions	Programming & implementation	4,357,655
39	PA Consulting Services	Consulting	133,147
40	Peaker Services, Inc.	Contractor	122,421
41	PricewaterhouseCoopers	Auditing/ Consulting	837,954
42	Quality Resource & Services	Inspection services	103,303
43	Rod Tabbert Construction, Inc.	Contractor	357,495
44	Spherion Corporation	Temporary employment service	126,397
45	State Line Contractors, Inc.	Contractor	312,086
46	Sweitzer Engineering	Engineering services	140,675
47	Technology Unlimited	Computer maintenance	147,082
48	Thelen Reid & Priest, LLC	Legal services	564,455
49	Tony Laslovich	Contractor	101,278
50	Towers Perrin	Consulting/Actuary	507,458
51	XENERGY, Inc.	Contract services	1,247,988
52	Washington Infrastructure	Contract services	223,677
53	Zacha Construction, Inc.	Construction & maintenance	136,373
54			
55	**Total Payments for Services**		$39,282,047
57	1/ Due to the multiple % allocations, it is not practical to separately identify amounts charged to the electric or gas utility.		

Sch. 13	POLITICAL ACTION COMMITTEES / POLITICAL CONTRIBUTIONS

The Montana Power Company does not make any contributions to Political Action Committees (PACs) or candidates.

There is an employee PAC - Citizens for Responsible Government / Employees of The Montana Power Company (CRG). CRG is an organization of employees and shareholders of Montana Power and its subsidiaries. All of the money contributed by members goes to support political candidates. No company funds may be spent in support of a political candidate. Officers and local representatives of CRG donate their time. Nominal administrative costs for such things as duplicating and postage are paid by the Company. These costs are charged to shareholder expense.

Sch. 14

PENSION COSTS

	Description	This Year	Last Year	% Change
1	**Plan Name: Retirement Plan for Employees**			
2	**of The Montana Power Company**			
3	Defined Benefit Plan	Yes	Yes	
4	Defined Contribution Plan (See Schedule 14A)			
5	Is the Plan overfunded?	No - 3/	Yes - 2/	
6				
7	Actuarial Cost Method	Projected Unit Credit Method		
8	IRS Code			
9	Annual Contribution by Employer	0	0	
10	Accumulated Benefit Obligation - 4/	241,360,765	221,222,867	9.10%
11	Projected Benefit Obligation - 4/	229,830,140	216,129,144	6.34%
12	Fair Value of Plan Assets - 4/	191,046,243	223,920,969	-14.68%
13				
14	Discount Rate for Benefit Obligations	7.00%	7.50%	-6.67%
15	Expected Long-Term Return on Assets	9.00%	9.00%	0.00%
16				
17	Net Periodic Pension Cost:			
18	Service Cost - 4/	3,675,916	4,089,862	-10.12%
19	Interest Cost - 4/	15,612,221	14,476,386	7.85%
20	Return on Plan Assets (Expected) -4/	(17,921,050)	(20,272,561)	-11.60%
21	Net Amortization - 4/	1,900,249	(1,336,297)	-242.20%
22	Special Termination Benefit Charge - 4/	-	9,814,262	-100.00%
23	Curtailment Charge	-	-	-
24	Settlement Charge	-	-	-
25	Total Net Periodic Pension Cost	3,267,336	6,771,652	-51.75%
26				
27	Minimum Required Contribution			
28	Actual Contribution	-	-	
29	Maximum Amount Deductible	-	-	
30	Benefit Payments	15,219,835	9,942,351	53.08%
31				
32	Montana Intrastate Costs:			
33	Pension Costs	NOT APPLICABLE		
34	Pension Costs Capitalized			
35	Accumulated Pension Asset (Liability) at Year End			
36				
37	Number of Company Employees : 1/			
38	Covered by the Plan			
39	Active - 4/	1,152	1,383	-16.70%
40	Retired - 4/	1,160	881	31.67%
41	Vested Former Employees (Deferred Inactive) - 4/	873	590	47.97%
42	Total Covered by the Plan - 4/	3,185	2,854	11.60%
43	Total Not Covered by the Plan			
44				

45 1/ Obtained from The Actuarial Valuation Report of the Retirement Plan for Employees of The
46 Montana Power Company, prepared as of January 1, 2001 and 2000 respectively.
47
48 2/ As of December 31, 2000, the fair value of assets was $223.9 million and the projected benefit obligation
49 was 216.1 million. However, there was an unrecognized net gain of $25.3 million that has not been
50 fully amortized pursuant to SFAS Statement No. 87. There is a prepaid pension cost of $10.8 million
51 as of December 31, 2000.
52
53 3/ As of December 31, 2001, the fair value of assets was $191.0 million and the projected benefit obligation
54 was 229.8 million. However, there was an unrecognized net loss of $20.6 million that has not been
55 fully amortized pursuant to SFAS Statement No. 87. There is a pension liability of $600,000
56 as of December 31, 2001.

Sch. 14	PENSION COSTS			
	Description	This Year	Last Year - 3/	
1	**Plan Name: Retirement Savings Plan**			
2				
3	Defined Benefit Plan (See Schedule 14)			
4	Defined Contribution Plan	Yes	Yes	
5	Is the Plan overfunded?			
6				
7				
8	Actuarial Cost Method			
9	IRS Code			
10	Annual Contribution by Employer			
11				
12	Accumulated Benefit Obligation			
13	Projected Benefit Obligation			
14	Fair Value of Plan Assets	109,333,678	138,602,820	-21.12%
15				
16	Discount Rate for Benefit Obligations			
17	Expected Long-Term Return on Assets			
18				
19	Net Periodic Pension Cost:			
20	Service Cost			
21	Interest Cost	NOT APPLICABLE		
22	Return on Plan Assets (Actual)			
23	Net Amortization			
24	Total Net Periodic Pension Cost			
25				
26	Minimum Required Contribution			
27	Actual Contribution	NOT APPLICABLE		
28	Maximum Amount Deductible			
29	Benefit Payments			
30				
31	Montana Intrastate Costs:			
32	Pension Costs	NOT APPLICABLE		
33	Pension Costs Capitalized			
34	Accumulated Pension Asset (Liability) at Year End			
35				
36	Number of Company Employees :			
37	Covered by the Plan -- Eligible -4/	1,313	1,032	27.23%
38	Not Covered by the Plan	-	-	
39	Active -- Participating	955	1,013	-5.73%
40	Retired			
41	Vested Former Employees, Retirees and -4/	358	19	1784.21%
42	Active-Noncontributing			
43	Total Covered by the Plan -4/	1,313	1,032	27.23%
44	Total Not Covered by the Plan	0	0	
45				
46				
47				
48	4/ 2000 numbers were restated to include SAS.			

Sch 15	OTHER POST EMPLOYMENT BENEFITS (OPEBS)			
	Description	This Year	Last Year	% Change
1	**General Information**	2/	1/	
2	Discount Rate for Benefit Obligations	7.00%	7.50%	-7.14%
3	Expected Long-Term Return on Assets	9.00%	9.00%	0.00%
4	Medical Cost Inflation Rate 3/	9.00%, 5.50%: 7	10.0%,5.50%: 7	
5	Actuarial Cost Method	Projected Unit Credit Actuarial		
6		Cost Method allocated from date of		
7		hire to full eligibility date.		
8	List each method used to fund OPEBs (ie: VEBA, 401(h)):			
9	Method - Tax Advantaged (Yes or No) YES			
10	Union Employees - VEBA			
11	Non-Union Employees - 401(h)			
12	Describe Changes to the Benefit Plan: None.			
13				
14	**Total Company**			
15				
16	Accumulated Post Retirement Benefit Obligation (APBO) - 6/	$26,454,217	$20,479,046	22.59%
17	Fair Value of Plan Assets - 6/	$5,871,614	$9,706,656	-65.31%
18				
19	List the amount funded through each funding method:			
20	VEBA - 7/	$461,137	$726,947	-57.64%
21	401(h) - 7/	1,293,925	756,619	41.53%
22	Other: Cash	811,379	639,256	21.21%
23	Total Amount Funded	$2,566,441	$2,122,822	17.29%
24				
25	List amount that was tax deductible for each type of funding:			
26	VEBA - 7/	$461,137	$726,947	-57.64%
27	401(h) - 7/	1,293,925	756,619	41.53%
28	Other: Cash	811,379	639,256	21.21%
29	Total Amount Tax Deductible	$2,566,441	$2,122,822	17.29%
30				
31	Net Periodic Post Retirement Benefit Cost:			
32	Service Cost - 6/	$419,695	$429,624	-2.37%
33	Interest Cost - 6/	1,851,224	1,560,506	15.70%
34	Return on Plan Assets (Expected) - 6/	(705,817)	(817,728)	15.86%
35	Amort. Of Transition Oblig. & Regulatory Asset-6/	791,706	837,029	-5.72%
36	Amortization of Prior Service Cost - 6/	138,644	145,885	-5.22%
37	Amortization of Gains or Losses - 6/	0	(128,109)	-100.00%
38	Total Net Periodic Post Retirement Benefit Cost	$2,495,452	$2,027,207	18.76%
39	Benefit Cost Expensed - 6/	$1,976,398	$1,558,922	21.12%
40	Benefit Cost Capitalized - 6/	374,318	425,713	-13.73%
41	Benefit Cost Charged to MPC Subs & Colstrip Owners- 5/,6/	144,736	42,571	70.59%
42	Total Benefit Costs	$2,495,452	$2,027,206	18.76%
43	Benefit Payments	$811,379	$639,256	21.21%
44				
45	Number of Company Employees :			
46	Covered by the Plans			
47	Active - 6/	1,156	1,386	-19.90%
48	Retired - 6/	1,025	759	25.95%
49	Retired Spouse/Dependents	44	28	36.36%
50	Total Covered by the Plans	2,225	2,173	2.34%
51	Total Not Covered by the Plans	210	264	-25.71%
52	1/ Obtained from MPC's 2000 FASB 106 Valuation. Assumptions and data are as of December 31, 2000.			
53	2/ Obtained from MPC's 2001 FASB 106 Valuation. Assumptions and data are as of December 31, 2001.			
54	3/ First Year, Ultimate, Years to Reach Ultimate.			

Sch 15A

OTHER POST EMPLOYMENT BENEFITS (OPEBS)

	Description	This Year	Last Year	% Change
1	**General Information**	4/	4/	
2	Discount Rate for Benefit Obligations			
3	Expected Long-Term Return on Assets			
4	Medical Cost Inflation Rate 3/			
5	Actuarial Cost Method			
6				
7				
8	List each method used to fund OPEBs (ie: VEBA, 401(h)):			
9	Method - Tax Advantaged (Yes or No) YES			
10	Union Employees - VEBA			
11	Non-Union Employees - 401(h)			
12	Describe Changes to the Benefit Plan: None.			
13				
14	**Montana**	4/	4/	
15				
16	Accumulated Post Retirement Benefit Obligation (APBO)			
17	Fair Value of Plan Assets			
18				
19	List the amount funded through each funding method:			
20	VEBA			
21	401(h)			
22	Other: Cash			
23	Total Amount Funded			
24				
25	List amount that was tax deductible for each type of funding:			
26	VEBA			
27	401(h)			
28	Other: Cash			
29	Total Amount Tax Deductible			
30				
31	Net Periodic Post Retirement Benefit Cost:			
32	Service Cost			
33	Interest Cost			
34	Return on Plan Assets - Estimated			
35	Amort. of Transition Oblig. & Regulatory Asset			
36	Amortization of Gains or Losses			
37	Total Net Periodic Post Retirement Benefit Cost			
38	Benefit Cost Expensed			
39	Benefit Cost Capitalized			
40	Benefit Cost Charged to MPC Subs & Colstrip Owners			
41	Total Benefit Costs			
42	Benefit Payments			
43				
44	Number of Company Employees :			
45	Covered by the Plans			
46	Active			
47	Retired			
48	Retired Spouse/Dependents			
49	Total Covered by the Plans			
50	Total Not Covered by the Plans			

51 4/ Substantially all of the amounts are subject to the PSC jurisdiction. Actual amounts that will be
52 expensed, will reflect reductions for amounts billed to others or allocated to Yellowstone National Park.
53 5/ Due to the sale of generating assets, there is no longer billing to Colstrip owners from 2000 forward.
54 6/ 2000 restatements.
55 7/ 2001 Trust funding was made on January 11, 2002.

Sch. 16	TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)				
Name/Title	Base Salary 1/	Other Comp. 2/	Total Comp.	Total Comp. Last Year	% Change
R. P. Gannon	$487,981	$12,019 <A			
Chairman of the Board		6,800 <B			
and Chief Executive		100,000 <C			
Officer		1,078 <D			
		2,239 <E			
		145 <F			
		780 <G			
		682 <H			
			$611,724	$764,340	-20%
J. D. Haffey	188,896	21,576 <A			
Executive Vice President and		6,800 <B			
Chief Operating Officer		80,523 <C			
		920 <E			
		380 <F			
		3,948 <G			
			303,043	327,701	-8%
J. P. Pederson	250,000	6,800 <B			
Vice Chairman and		34,375 <C			
Chief Financial Officer		617 <E			
			291,792	359,473	-19%
D. A. Johnson	173,935	6,800 <B			
Vice President,		52,729 <C			
Distribution Services		351 <E			
		249 <F			
			234,064	231,201	1%
M. E. Zimmerman	182,231	6,800 <B			
Vice President and		26,013 <C			
General Counsel		237 <D			
		1,558 <F			
		150 <H			
			$216,989	$242,018	-10%
W. A. Pascoe					
Vice President,					
Transmission Services					
D. J. Sullivan	CONFIDENTIAL INFORMATION				
Chief Information Officer	NOT REQUIRED FOR GENERAL DISTRIBUTION				

Sch. 16

TOP TEN MONTANA COMPENSATED EMPLOYEES (ASSIGNED OR ALLOCATED)

Name/Title	Base Salary 1/	Other Comp. 2/	Total Comp.	Total Comp. Last Year	% Change
P. K. Merrell Vice President, Human Resources					
M. P. Manion Legal Services					
E. M. Senechal Treasurer					

CONFIDENTIAL INFORMATION

NOT REQUIRED FOR GENERAL DISTRIBUTION

1/ Salary includes the employees' annual base federally taxable earnings, pretax contributions to the Company's Deferred Savings and Employee Stock Ownership (401(K)) Plan, pretax Section 125 flexible spending account contributions, pretax medical premium contributions, and, in some cases, tax deferred Executive Benefit Restoration Plan contributions.

2/ All Other Compensation for named employees consists of the following:

A> Vacation time sold back to the Company. The vacation sellback program is available to all employees.

B> The value of the Company's matching contribution of stock (through 10/31/01) and cash (11/1/01 - 12/31/01) made to the employee's account under the Retirement Savings Plan (401(K) plan) sponsored by the Company.

C> Incentive Compensation Plan which were earned under the 2000 EVA Bonus Plan.

D> Taxable fringe benefit.

E> Imputed taxable income on Company-paid life insurance premiums.

F> Company-paid physical examinations.

G> Personal use of company vehicles.

H> Spot cash bonus awards.

Sch. 17

COMPENSATION OF TOP FIVE CORPORATE EMPLOYEES - SEC INFORMATION

Name/Title	Base Salary 1/	Other Comp. 2/	Total Comp.	Total Comp. Last Year	% Change
R. P. Gannon Chairman of the Board and Chief Executive Officer	$487,981	$12,019 <A 6,800 <B 100,000 <C 1,078 <D 2,239 <E 145 <F 780 <G 682 <H	$611,724	$764,340	-20%
J. D. Haffey Executive Vice President and Chief Operating Officer	188,896	21,576 <A 6,800 <B 80,523 <C 920 <E 380 <F 3,948 <G	303,043	327,701	-8%
J. P. Pederson Vice Chairman and Chief Financial Officer	250,000	6,800 <B 34,375 <C 617 <E	291,792	359,473	-19%
D. A. Johnson Vice President, Distribution Services	173,935	6,800 <B 52,729 <C 351 <E 249 <F	234,064	231,201	1%
M. E. Zimmerman Vice President and General Counsel	182,231	6,800 <B 26,013 <C 237 <D 1,558 <F 150 <H	$216,989	$242,018	-10%

1/ Salary includes the employees' annual base federally taxable earnings, pretax contributions to the Company's Deferred Savings and Employee Stock Ownership (401(K)) Plan, pretax Section 125 flexible spending account contributions, pretax medical premium contributions, and, in some cases, tax deferred Executive Benefit Restoration Plan contributions.

2/ All Other Compensation for named employees consists of the following:

A> Vacation time sold back to the Company. The vacation sellback program is available to all employees.

B> The value of the Company's matching contribution of stock (through 10/31/01) and cash (11/1/01 - 12/31/01) made to the employee's account under the Retirement Savings Plan (401(K) plan) sponsored by the Company.

C> Incentive Compensation Plan which were earned under the 2000 EVA Bonus Plan.

D> Taxable fringe benefit.

E> Imputed taxable income on Company-paid life insurance premiums.

F> Company-paid physical examinations.

G> Personal use of company vehicles.

H> Spot cash bonus awards.

Sch. 18

BALANCE SHEET 1/

	Account Title	This Year	Last Year	% Change
1	**Assets and Other Debits**			
2	**Utility Plant**			
3	101 Plant in Service 2/	$1,545,871,892	$1,221,842,478	26.52%
4	105 Plant Held for Future Use	8,984	8,984	0.00%
5	107 Construction Work in Progress	10,447,595	1,805,954	478.51%
6	108 Accumulated Depreciation Reserve	(539,286,806)	(493,655,655)	-9.24%
7	111 Accumulated Amortization & Depletion Reserves	(12,169,750)	(9,683,037)	-25.68%
8	114 Electric Plant Acquisition Adjustments	3,106,285	3,106,285	0.00%
9	115 Accumulated Amortization-Electric Plant Acq. Adj.	(2,346,971)	(2,252,057)	-4.21%
10	117 Gas Stored Underground-Noncurrent	42,397,528	40,710,265	4.14%
11	**Total Utility Plant**	1,048,028,757	761,883,217	37.56%
12	**Other Property and Investments**			
13	121 Nonutility Property	2,061,961	2,780,825	-25.85%
14	122 Accumulated Depr. & Amort.-Nonutililty Property	(87,849)	(69,747)	-25.95%
15	123.1 Investments in Subsidiary Companies	807,438,353	759,190,205	6.36%
16	123 Investments in Colstrip Unit 4 & YNP	44,835,353	46,158,027	-2.87%
17	124 Other Investments	21,447,804	21,162,587	1.35%
18	128 Miscellaneous Special Funds	1,429,900	1,393,095	2.64%
19	**Total Other Property & Investments**	877,125,522	830,614,992	5.60%
20	**Current and Accrued Assets**			
21	131 Cash	(3,630,377)	(4,330,121)	16.16%
22	135 Working Funds	52,365	89,047	-41.19%
23	136 Temporary Cash Investments	7,000,000	-	
24	141 Notes Receivable	181,476	254,123	-28.59%
25	142 Customer Accounts Receivable	43,310,904	75,778,151	-42.85%
26	143 Other Accounts Receivable	5,093,295	22,238,445	-77.10%
27	144 Accumulated Provision for Uncollectible Accounts	(1,223,900)	(1,163,900)	-5.16%
28	145 Notes Receivable-Associated Companies	-	60,980,872	-100.00%
29	146 Accounts Receivable-Associated Companies	34,656,551	125,321,575	-72.35%
30	151 Fuel Stock	-	151,070	-100.00%
31	154 Plant Materials and Operating Supplies	9,111,610	10,238,825	-11.01%
32	165 Prepayments	16,272,659	11,574,145	40.59%
33	171 Interest and Dividends Receivable	12,114	2,380,228	-99.49%
34	172 Rents Receivable	97,443	266,113	-63.38%
35	173 Accrued Utility Revenues	22,696,131	27,744,975	-18.20%
36	174 Miscellaneous Current & Accrued Assets	127,893	64,019	99.77%
36	**Total Current & Accrued Assets**	133,758,164	331,587,567	-59.66%
37	**Deferred Debits**			
38	181 Unamortized Debt Expense	3,763,307	3,353,218	12.23%
39	182 Regulatory Assets	209,378,179	206,288,584	1.50%
40	183 Preliminary Survey and Investigation Charges	625,340	625,340	0.00%
41	184 Clearing Accounts	(78)	(27,020)	99.71%
42	185 Temporary Facilities	78	(12,238)	100.63%
43	186 Miscellaneous Deferred Debits	37,476,788	14,500,996	158.44%
44	189 Unamortized Loss on Reacquired Debt	3,607,678	3,914,566	-7.84%
45	190 Accumulated Deferred Income Taxes	175,932,149	170,007,486	3.48%
46	191 Unrecovered Purchased Gas Costs	(6,659,440)	14,414,108	-146.20%
47	**Total Deferred Debits**	424,124,001	413,065,040	2.68%
48	**TOTAL ASSETS and OTHER DEBITS**	$2,483,036,444	$2,337,150,816	6.24%

Sch. 18 cont.	**BALANCE SHEET** 1/			
	Account Title	This Year	Last Year	% Change
1	**Liabilities and Other Credits**			
2	**Proprietary Capital**			
3	201 Common Stock Issued	$706,100,642	$705,656,783	0.06%
4	204 Preferred Stock Issued	58,063,500	58,063,500	0.00%
5	207 Premium on capital stock	-	-	
6	211 Miscellaneous Paid-In Capital	2,347,399	2,391,602	-1.85%
7	213 Discount on Capital Stock	(815,700)	(815,700)	0.00%
8	214 Capital Stock Expense	(93,888)	(93,889)	0.00%
9	215 Appropriated Retained Earnings	6,238,312	6,238,312	0.00%
10	216 Unappropriated Retained Earnings	610,411,500	595,587,557	2.49%
11	217 Reacquired capital stock	(205,656,384)	(205,656,384)	0.00%
12	**Total Proprietary Capital**	1,176,595,381	1,161,371,781	1.31%
13	**Long Term Debt**			
14	221 Bonds	327,402,000	177,402,000	84.55%
15	224 Other Long Term Debt	145,666,000	209,197,000	-30.37%
16	226 Unamortized Discount on Long Term Debt-Debit	(3,210,502)	(2,443,514)	-31.39%
17	**Total Long Term Debt**	469,857,498	384,155,486	22.31%
18	**Other Noncurrent Liabilities**			
19	227 Obligations Under Capital Leases-Noncurrent	-	4,166	-100.00%
20	228.1 Accumulated Provision for Property Insurance	410,424	939,516	-56.32%
21	228.2 Accumulated Provision for Injuries and Damages	3,314,632	2,790,548	18.78%
22	228.3 Accumulated Provision for Pensions and Benefits	8,169,359	6,736,462	21.27%
23	228.4 Accumulated Miscellaneous Operating Provisions	5,155,912	7,350,000	-29.85%
24	**Total Other Noncurrent Liabilities**	17,050,327	17,820,692	-4.32%
25	**Current and Accrued Liabilities**			
25	231 Notes Payable	-	75,000,000	-100.00%
26	232 Accounts Payable	23,509,160	70,843,169	-66.82%
27	233 Notes Payable to Associated Companies	24,810,881	49,372,117	-49.75%
28	234 Accounts Payable to Associated Companies	75,088,194	157,968,250	-52.47%
29	235 Customer Deposits	1,398,414	849,654	64.59%
30	236 Taxes Accrued	(623,365)	27,568,964	-102.26%
31	237 Interest Accrued	6,572,178	4,821,957	36.30%
32	238 Dividends Declared	776,264	1,456,066	-46.69%
33	241 Tax Collections Payable	(142,569)	(304,174)	53.13%
34	242 Miscellaneous Current and Accrued Liabilities	31,537,543	30,465,232	3.52%
35	243 Obligations Under Capital Leases-Current	10,962	22,542	-51.37%
36	**Total Current and Accrued Liabilities**	162,937,662	418,063,777	-61.03%
37	**Deferred Credits**			
38	252 Customer Advances for Construction	21,030,639	20,944,582	0.41%
39	253 Other Deferred Credits	58,246,304	6,685,685	771.21%
40	254 Regulatory Liabilities	329,414,254	60,280,578	446.47%
41	255 Accumulated Deferred Investment Tax Credits	12,718,195	13,162,867	-3.38%
42	257 Unamortized Gain on Reacquired Debt	13,149	22,360	-41.20%
43	281-283 Accumulated Deferred Income Taxes	235,173,035	254,643,008	-7.65%
44	**Total Deferred Credits**	656,595,576	355,739,080	84.57%
45	**TOTAL LIABILITIES and OTHER CREDITS**	$2,483,036,444	$2,337,150,816	6.24%
46	1/ Includes CMP and Montana Power Capital I; excludes Colstrip Unit 4 and Yellowstone National Park.			
47				
48	2/ The 2000 plant in service balance included a credit amount of approximately $249,000,000 in account			
49	102. This represented the excess of proceeds over the book value of electric generating assets sold			
50	in 1999. This credit was moved to regulatory liabilities in 2001 in accordance with a FERC			
49	order in Docket No. AC00-70-000.			

NOTES TO THE FINANCIAL STATEMENTS

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

❑ BASIS OF ACCOUNTING

Our accounting policies conform to generally accepted accounting principles. With respect to our utility operations, these policies are in accordance with the accounting requirements and ratemaking practices of applicable regulatory authorities.

❑ USE OF ESTIMATES

Preparing financial statements requires the use of estimates based on available information. Actual results may differ from our accounting estimates as new events occur or we obtain additional information.

❑ FINANCIAL STATEMENT PRESENTATION

The financial statements are presented on the basis of the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts. This report differs from generally accepted accounting principles due to FERC requiring the reflection of subsidiaries on the equity method of accounting, which differs from Statement of Financial Accounting Standards (SFAS) No. 94, "Consolidation of All Majority-Owned Subsidiaries. SFAS No. 94 requires that all majority-owned subsidiaries be consolidated. The other differences are comparative statements of retained earnings and cash flows and net income per share are not presented.

❑ CASH AND CASH EQUIVALENTS AND TEMPORARY CASH INVESTMENTS

We consider all liquid investments with original maturities of three months or less to be cash equivalents, and investments with original maturities over three months and up to one year as temporary investments. All temporary investments at December 31, 2001, had original maturities of three months or less.

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❑ PROPERTY, PLANT, AND EQUIPMENT

The following table provides year-end balances of the major classifications of our property, plant, and equipment, which we record at cost:

	December 31, 2001	December 31, 2000
	(Thousands of Dollars)	
UTILITY PLANT:		
Electric:		
Generation (including our share of jointly owned)	$ 9,488	$ (238,431)
Transmission	397,219	395,218
Distribution	623,054	597,871
Other	125,305	91,163
Natural Gas:		
Storage	72,617	71,659
Transmission	173,750	167,416
Distribution	154,450	151,039
Other	45,949	31,539
Total plant	$1,601,832	$1,267,474

We capitalize the cost of plant additions and replacements, including an allowance for funds used during construction (AFUDC) of utility plant. We determine the rate used to compute AFUDC in accordance with a formula established by FERC. This rate averaged 6.1 percent for 2001 and 8.6 percent for 2000.

We charge costs of utility depreciable units of property retired, plus costs of removal less salvage, to accumulated depreciation and recognize no gain or loss. We charge maintenance and repairs of plant and property, as well as replacements and renewals of items determined to be less than established units of plant, to operating expenses.

Included in the plant classifications are utility plant under construction in the amounts of $10,448,000 and $1,806,000 for 2001 and 2000, respectively.

We record provisions for depreciation at amounts substantially equivalent to calculations made on a straight-line method by applying various rates based on useful lives of properties determined from engineering studies. As a percentage of the depreciable utility plant at the beginning of the year, our provision for depreciation of utility plant was approximately 3.4 percent for 2001 and 3.5 percent for 2000.

❑ REVENUE AND EXPENSE RECOGNITION

We record operating revenues monthly on the basis of consumption or services rendered. To match revenues with associated expenses, we accrue unbilled revenues for electric and natural gas services delivered to customers but not yet billed at month-end.

The Emerging Issues Task Force (EITF) Issue No. 98-10 requires that energy contracts entered into under "trading activities" be marked to market with the gains or losses shown net in the income statement. EITF 98-10 became effective for fiscal years beginning after December 15, 1998. We adopted

EITF 98-10 as of January 1, 1999, and accordingly mark to market energy contracts that qualify as "trading activities." The cumulative effect of adopting EITF 98-10 had no material effect on our financial position, results of operations, or cash flows.

❑ **REGULATORY ASSETS AND LIABILITIES**

For our regulated operations, we follow SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." Pursuant to this pronouncement, certain expenses and credits, normally reflected in income as incurred, are recognized when included in rates and recovered from or refunded to the customers. The significant regulatory assets and liabilities we have recorded are discussed below.

Regulatory assets and liabilities related to electric supply were included in our filing with the Montana Public Service Commission (PSC) to address stranded costs. These amounts offset the gain realized on the sale of the electric generating assets in the determination of net stranded costs. Amortization of these items stopped in February 2000 when they were removed from rates. The electric supply related regulatory assets and liabilities were removed from the balance sheet in February of 2002 as a result of the PSC order in our Tier II rate filing. For further information on the effects of the sale of our electric generating assets and our Tier II filing, see Note 2, "Deregulation, Regulatory Matters, and 1999 Sale of Electric Generating Assets."

In Docket No. AC00-70-000, FERC allowed us to move the net proceeds from the electric generating asset sale from account 102, "Electric Plant Purchased or Sold," to account 254, "Other Regulatory Liabilities." This transfer was done in February 2001 and at December 31, 2001 the liability balance was $257,519,000.

In the ratemaking process, tax costs and benefits related to certain temporary differences are recovered in rates on an as paid or "flow-through" basis. SFAS No. 109, "Accounting for Income Taxes," requires that tax assets and liabilities be reflected on the balance sheet on an accrual basis. This timing difference requires that we recognize a regulatory asset for taxes accrued but not yet recovered in rates. That regulatory asset was $61,375,000 and $88,822,000 as of December 31, 2001 and 2000, respectively.

In August 1985, the Montana Public Service Commission (PSC) issued an order allowing us to recover deferred carrying charges and depreciation expenses over the remaining life of Colstrip Unit 3. These recoveries compensated us for unrecovered costs of our investment for the period from January 10, 1984, to August 29, 1985, when we placed the plant in service. We were amortizing this asset to expense, and recovering in rates, $1,831,000 per year. At December 31, 2001 and 2000, the unamortized amount was $38,337,000.

We also include costs related to our Demand Side Management (DSM) programs in other regulatory assets. This amount was $27,956,000 for both 2001 and 2000. These costs were in rate base and we were amortizing them to income over a 10-year period.

We recorded a regulatory liability of $32,549,000 in connection with the sale of our unregulated oil and natural gas operations on October 31, 2000. The liability represents the portion of the proceeds from the sale attributable to properties previously in the natural gas utility's rate base. Based on gas stipulation agreements addressing the removal of natural gas production properties from regulation, we had agreed to share this amount with our natural gas utility ratepayers and are amortizing this amount over a one-year period beginning in February 2001. In September 2001, after all testimony addressing the amount of sharing had been filed with the PSC, we reached an agreement with intervening parties to increase the amount of the credit to approximately $56,300,000. This $23,751,000 increase, along with approximately $5,540,000 in interest from the date of sale, was added to the liability and will be credited to customers' bills over a two-year period beginning in January 2002. At December 31, 2001 and 2000, the balance in this account was $33,426,000 and $32,549,000, respectively.

Certain other amounts represent items that we are amortizing currently or are subject to future regulatory confirmation.

Changes in regulation or changes in the competitive environment could result in our not meeting the criteria of SFAS No. 71. If we were to discontinue application of SFAS No. 71 for some or all of our regulated operations, we would have to eliminate the related regulatory assets and liabilities from the balance sheet. We would include the associated expenses and credits in income in the period when the discontinuation occurred, unless recovery of those costs was provided through rates charged to those customers in portions of the business that were to remain regulated.

- **STORM DAMAGE AND ENVIRONMENTAL REMEDIATION COSTS**

When losses from costs of storm damage and environmental remediation obligations for our utility operations are probable and reasonably estimable, we charge these costs against established, approved operating reserves.

- **INCOME TAXES**

We defer income taxes to provide for the temporary differences between the financial reporting basis and the tax basis of our assets and liabilities. For further information on income taxes, see "Regulatory Assets and Liabilities" mentioned above and Note 3, "Income Tax Expense."

- **ASSET IMPAIRMENT**

In accordance with SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of," we periodically review long-lived assets for impairment whenever events or changes in circumstances indicate that we may not recover the carrying amount of an asset.

- **COMPREHENSIVE INCOME**

Comprehensive income consists of net income (loss) and other comprehensive income (loss). For the years ended December 31, 2001 and 2000, other comprehensive loss consisted of marked to market adjustments related to derivative financial instruments, loss on a benefit restoration plan, and foreign currency translation adjustments of the assets and liabilities of Canadian-Montana Pipe Line Corporation (CMP). These amounted to a decrease to retained earnings of approximately $410,000 and $1,695,000, respectively.

The accumulated balance of other comprehensive income (loss) at December 31, 2001 and 2000, was $2,086,000 and $1,676,000, respectively.

❑ DERIVATIVE FINANCIAL INSTRUMENTS

Electric Swap Agreements

Long-term power supply agreements, primarily one with a large industrial customer, exposed us to commodity price risk. We were exposed to this risk to the extent that a portion of the electric energy we were required to sell to our industrial customers at fixed rates was purchased at prices indexed to a wholesale electric market, which can be higher than the fixed sales rate that we received pursuant to our power supply agreements. We mitigated our exposure to losses on these agreements with financial derivative instruments called "price swaps" and offsetting electric energy purchase and sales agreements.

Since June 1998, we have had a price swap agreement with one of our industrial customers that converts 43 MWs of the Mid-Columbia (Mid-C) index price of our supply agreement with that customer to a fixed price through May 2001. In fiscal year 2000, we also entered into another price swap with a counterparty that effectively hedged 35 MWs of the anticipated market-based purchases to supply that agreement through March 2001.

Prior to fiscal year 2001, in accordance with the provisions of SFAS No. 80, "Accounting for Futures Contracts," we recognized gains and losses from the financial swaps in the same period in which we recognized the sales and related purchases under that agreement. For fiscal year 2000, we recognized a net gain of approximately $16,000,000 from these financial swaps and losses of approximately $32,200,000 from supplying large industrial customers. For more specific information about the commodity price risk that we face as a result of our long-term power supply agreements, see Note 10, "Contingencies," in the "Long-Term Power Supply Agreements" section.

An estimate of the fair market value of the swaps based on the Mid-C forward prices as of December 29, 2000 aggregated a gain of approximately $21,800,000 as of December 31, 2000, which would offset approximately 40 percent of the expected losses on the above power supply agreements.

Effective January 1, 2001, we adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, "Accounting for Certain Derivative Transactions and Hedging Activities." These pronouncements expand the definition of a derivative and require that all derivative instruments be recorded as assets or liabilities on an entity's balance sheet at fair value. Accounting for gains and losses resulting from changes in the fair value of those derivatives is dependent on the use of the derivative and whether it qualifies for hedge accounting.

At January 1, 2001, we had price swap agreements that hedged our exposure to variability in expected cash flows attributable to commodity price risk. Specifically, long-term power supply agreements, primarily one with a large industrial customer, expose us to that risk, to the extent that a portion of the electric energy we are required to sell to our industrial customers at fixed rates is purchased at prices indexed to the Mid-Columbia (Mid-C) wholesale electric market, which can be higher than the fixed sales rates. Another agreement to sell 1,760,000 dekatherms of natural gas storage at a monthly price based on the Alberta Energy Company "C" Hub (AECO-C) index, from October 2000 to March 2001, exposed us to adverse fluctuation in that market price index. In accordance with the provisions of SFAS No. 133, we marked to market at January 1, 2001 our price swap agreements hedging these forecasted electric energy and natural gas sales, with a corresponding credit entry to "Other comprehensive income" for approximately $11,300,000 after income taxes. That entry represented our cumulative transition adjustment in adopting SFAS No. 133, and is reflected in the Combined Statement of Other Equity in 2001.

For the first seven months of 2001, we were exposed to commodity price risk because a portion of the electric energy we were required to sell at fixed rates to industrial customers was purchased at prices indexed to a wholesale electric market, which could be and was higher than the fixed sales rate. We used derivative financial instruments called "price swaps" and offsetting electric energy purchase and sales agreements to hedge our exposure to losses on these power supply agreements with large industrial customers.

For the year ended December 31, 2001, the electric energy sales resulted in an after-tax loss of $25,300,000, and the price swaps hedging those sales in an after-tax gain of approximately $7,200,000. At December 31, 2001, we did not have agreements to purchase electric energy for sales to industrial customers or power marketers, nor did we have financial derivative agreements to hedge such transactions.

Natural Gas Utility Swaps

By drilling wells and adding compression at our Cobb storage reservoir, we were able to sell natural gas that had been held in reserve to provide firm storage deliverability to our customers. We therefore contracted to sell, from October 2000 through March 2001, 1,760,000 dekatherms from that reservoir at a monthly price based on the Alberta Energy Company "C" Hub (AECO-C) index. To reduce our exposure to fluctuations of the market index price, we entered into a swap agreement with a counterparty that effectively converted that index price to a fixed price for 903,000 dekatherms associated with these sales from December 2000 through February 2001.

For December 2000, we recognized a loss of approximately $300,000 on the swap and a profit of approximately $1,200,000 on the sale of the Cobb storage natural gas. Based on the AECO-C forward prices at December 29, 2000, we estimated a loss of approximately $3,000,000 on the swap to offset profits of $4,900,000 on the sale through February 2001. We deferred the net profit of these transactions in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," and will recognize this amount in income as amounts are reflected in rates.

❑ **FAIR VALUE OF FINANCIAL INSTRUMENTS**

	2001		2000	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Thousands of Dollars)			
ASSETS:				
Investments	$ 21,448	$ 21,448	$ 21,127	$ 21,127
LIABILITIES:				
Long-term debt	$ 469,857	$ 458,861	$ 384,155	$ 381,654

The following methods and assumptions were used to estimate fair value:

- Investments - The carrying value of most of the investments approximates fair value as they have short maturities or the carrying value equals their cash surrender value. The investments consist mainly of the cash value of insurance policies associated with an unfunded, nonqualified benefit plan for senior management, executives, and directors.

- Long-term debt - The fair value was estimated using quoted market rates for the same or similar instruments. Where quotes were not available, fair value was estimated by discounting expected future cash flows using year-end incremental borrowing rates.

NOTE 2 - DEREGULATION, REGULATORY MATTERS, AND 1999 SALE OF ELECTRIC GENERATING ASSETS

❑ **DEREGULATION**

The electric and natural gas utility businesses in Montana are transitioning to a competitive market in which commodity energy products and related services are sold directly to wholesale and retail customers.

Electric

Montana's Electric Utility Industry Restructuring and Customer Choice Act (Electric Act), passed in 1997, provides that all customers will be able to choose their electric supplier by July 1, 2002, with our electric utility acting as default supplier through the transition period. As default supplier, we are obligated to continue to supply electric energy to customers in our service territory who have not chosen, or have not had an opportunity to choose, other power suppliers during the transition period. This obligation requires us to develop an energy supply portfolio to meet these customers' electric needs. Buyback contracts with PPL Montana, LLC (PPL Montana), the purchaser of our former electric generating assets, allow us to purchase power necessary to serve these customers through the transition period ending June 30, 2002.

In its 2001 session, the Montana Legislature passed House Bill 474 (HB 474), which extends the transition period through June 30, 2007. This law also provides for the use of a cost-recovery mechanism that ensures all prudently incurred electric energy supply costs of the default supplier are fully recoverable in rates. Initiative 117, which if passed would repeal HB 474, has been approved for inclusion on the November 2002 ballot in Montana. In the event that HB 474 is repealed, Montana Law would continue the transition period through at least June 30, 2007, and provide full cost recovery.

On October 29, 2001, Montana Power filed with the PSC the default supply portfolio, containing a mix of long and short-term contracts that were negotiated in order to provide electricity to default supply customers. This filing seeks approval of the default supply portfolio contracts and establishment of default supply rates for customers who have not chosen alternative suppliers by July 1, 2002. We expect that the costs of the supply portfolio and a competitive transition charge for out-of-market QF costs, as discussed below, will increase residential electric rates by approximately 20 percent beginning July 1, 2002. As discussed below, this will be offset for one year by a credit that reduces the increase to 12.8 percent. If the PSC does not approve the default supply portfolio, we may be required to seek alternative sources of supply. While we believe that we have met our default supply obligations prudently, the PSC could also disallow the recovery of costs incurred in entering into the default supply portfolio if a determination is made that the contracts were not entered into prudently.

On that same day, Montana Power submitted an updated Tier II filing with the PSC, addressing the recovery of transition costs of generation assets and other power-purchase contracts, generation-related regulatory asset transition costs, and transition costs associated with the out-of-market QF power-purchase contract costs. Previously, Montana Power initiated litigation in Montana District Court in Butte to address the ability to use tracking mechanisms to ensure fair and accurate recovery of these costs. Although the District Court ruled that the PSC must allow tracking mechanisms in the transition plan proposal, the Montana Supreme Court reversed this decision on appeal by the PSC and the Large Customer Group, which consists of various large industrial customers. Together with NorthWestern, the Montana Consumer Counsel, Commercial Energy and the Large Customer Group, on December 28, 2001, Montana Power submitted to the PSC an agreed upon stipulation settling the transition cost recovery in the Tier II filing and approving the sale to NorthWestern. The stipulation calls for Montana Power, through Touch America, and NorthWestern to establish a $30,000,000 account that will be used to provide a credit for our electric distribution customers. The credit will be provided over a one year period to customers on a per kilowatt-hour (Kwh) basis beginning on July 1, 2002, when our current below market energy supply contract expires. The credit will reduce a projected 20 percent increase in electric rates at that time to about 12.8 percent for the next 12 months. The stipulation also states that customers shall have no obligation to pay any transition costs accrued under or relating to the accounting orders issued by the PSC. These accrued transition costs through December 31, 2001, amount to $23,000,000. Another portion of the stipulation establishes the net present value (NPV) of out-of-market QF transition costs at $244,711,065, a reduction of $60,000,000, from the NPV presented in our October 29, 2001 filing. The effects of the stipulation were contingent upon the approval of the PSC and the consummation of the sale. On January 31, 2002, the PSC unanimously approved the stipulation.

Natural Gas

Montana's Natural Gas Utility Restructuring and Customer Choice Act, also passed in 1997, provides that a natural gas utility may voluntarily offer its customers choice of natural gas suppliers and provide open access. We have opened access on our gas transmission and distribution systems, and all of our natural gas customers have the opportunity of gas supply choice.

❑ **REGULATORY MATTERS**

The PSC regulates our transmission and distribution services and approves the rates that we charge for these services, while FERC regulates our transmission services and our remaining generation operations. Current regulatory issues are discussed below.

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Sale of the Utility Business

Together with NorthWestern, Montana Power filed joint applications with FERC on December 20, 2000, and with the PSC on January 11, 2001, seeking approval of the sale of the utility business formerly held by Montana Power to NorthWestern. FERC issued its approval on February 20, 2001. The PSC issued an order in June 2001 denying the joint application, claiming that insufficient information had been provided for it to fully evaluate whether the transaction is in the public interest. The PSC itemized additional information that must be provided before processing of the case could continue. Montana Power re-filed the joint application with the PSC in August 2001 and the PSC established a procedural schedule setting January 31, 2002 as the date for issuance of an order. As discussed above, together with NorthWestern, the Montana Consumer Counsel, Commercial Energy, and the Large Customer Group, on December 28, 2001, Montana Power submitted to the PSC an agreed-upon stipulation relating to the Tier II filing and the approval of the sale to NorthWestern Corporation. On January 31, 2002, the PSC unanimously approved the stipulation. The stipulation and the following PSC Order recognized that NorthWestern sufficiently demonstrated its capability to assume responsibility for the utility operations and will continue to be fit, willing and able provider of adequate service and facilities at just and reasonable rates. The utility business was sold to NorthWestern on February 15, 2002. For accounting convenience, due to the burden of a mid-month closing, both parties agreed to an effective date for the sale as of the opening of business on February 1, 2002.

Pending Transmission Asset Sale

In accordance with our Asset Purchase Agreement with PPL Montana, we expect to sell our portion of the 500-kilovolt transmission system associated with Colstrip Units 1, 2, and 3 for $97,100,000, subject to the receipt of required regulatory approvals. We expect this transaction to close in 2002.

PSC

Electric Rates

In August 2000, Montana Power filed a combined request for increased electric and natural gas rates with the PSC, requesting increased annual electric transmission and distribution revenues of approximately $38,500,000, with a proposed interim annual increase of approximately $24,900,000. On November 28, 2000, the PSC granted Montana Power an interim electric rate increase of approximately $14,500,000, with hearings on this submission beginning in January 2001. On May 8, 2001, Montana Power received a final order from the PSC resulting in an annual delivery service revenue adjustment of $16,000,000, including the $14,500,000 interim increase granted on November 28, 2000.

On June 27, 2001, the PSC issued an order stating that they continue to have jurisdiction over the utility business as a fully integrated public utility, in spite of the December 17, 1999 sale of our electric generating facilities. The order requires that, if we desire a power supply rate change at the end of the rate moratorium on July 1, 2002, we must make a filing containing information that supports what rates would be if the regulatory system in place prior to deregulation remained intact. Montana Power filed a motion for reconsideration with the PSC, which was subsequently denied. Montana Power has since filed a complaint against the PSC in Montana State District Court in Helena, disputing this order. We cannot predict the ultimate outcome of this matter or its potential effect on our financial position or results of operation.

Natural Gas Rates

As discussed above, in August 2000, Montana Power filed a combined request for increased natural gas and electric rates with the PSC. Montana Power requested increased annual natural gas revenues of approximately $12,000,000, with a proposed interim annual increase of approximately $6,000,000. On November 28, 2000, the PSC granted Montana Power an interim natural gas rate increase of approximately $5,300,000. On May 8, 2001, Montana Power received a final order from the PSC resulting in an annual delivery and gas storage service revenue increase of $4,300,000. Because the amount established in the final order was less than the interim order, Montana Power began including a credit for the difference collected from November 2000 through May 2001, with interest, in customers' bills over a six-month period starting October 1, 2001.

In January 2001, Montana Power submitted to the PSC an Annual Gas Cost Tracker requesting an increase of approximately $51,000,000. At that time, Montana Power also submitted a Compliance Filing for a credit of approximately $32,500,000 associated with a sharing of the proceeds from the sale of gathering and production properties previously included in the natural gas utility's rate base. As a result, effective February 1, 2001, Montana Power began collecting a net amount of approximately $18,500,000 in revenues over a one-year period. In September 2001, after all testimony addressing the amount of sharing had been filed with the PSC, Montana Power reached an agreement with intervening parties to increase the amount of the credit to approximately $56,300,000. This $23,800,000 increase, along with approximately $5,300,000 in interest from the date of sale, was charged to expense during 2001 and will be credited to customers' bills over a two-year period beginning January 1, 2002.

On December 7, 2001, Montana Power filed our Annual Gas Cost Tracker request with the PSC for the tracking year beginning November 1, 2001.

FERC

Through a filing with FERC in April 2000, we are seeking recovery of transition costs associated with serving two wholesale electric cooperatives. A FERC decision on this filing, which corresponds with our transition-costs recovery proceedings with the PSC in Montana, has been on hold pending a PSC Tier II order. On January 31, 2002, the Montana PSC approved a stipulation settling transition cost recovery for retail customers in Montana. Discussions with the wholesale electric cooperatives involved in the FERC filing are expected to resume in the near future.

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❑ 1999 SALE OF ELECTRIC GENERATING ASSETS

Assets Sold

On December 17, 1999, in accordance with the Asset Purchase Agreement entered into with PPL Montana, Montana Power sold substantially all of our electric generating assets and related contracts. Montana Power also sold an immaterial amount of associated transmission assets, totaling less than 40 miles. The asset sale did not include the Milltown Dam near Missoula, Montana (gross capacity of approximately 3 MWs) or any of our QF purchase-power contracts. It also did not include our leased share of the Colstrip Unit 4 generation or transmission assets.

As expected, the sale of our electric generating assets in December 1999 reduced the utility's net income for 2000. Utility revenues decreased because of discontinued off-system revenues that related to the electric generating assets sold. In addition, we no longer earn a return on our shareholders' investment in the electric generating assets. Before the sale, revenues covered the costs of operating the generating plants, taxes and interest, and earned a return on our shareholders' investment. Since the sale, we continue to bill our core customers for energy supply, but now these revenues recover the costs of the power that we purchase to serve these customers. The energy that we formerly generated and sold to core customers is now purchased pursuant to buyback contracts. The maximum price that we pay for power in the buyback contracts, $22.25/MWh, represents our net fully allocated supply costs of service in current rates, replacing operations and maintenance expense, property tax expense, depreciation expense, and return on investment associated with the electric generating assets.

In the sale of these assets, Montana Power generally retained all pre-closing obligations, and the purchaser generally assumed all post-closing obligations. However, with respect to environmental liabilities, the purchaser assumed all pre-closing (with certain limited exceptions) and post-closing environmental liabilities associated with the purchased assets.

While the purchaser assumed pre-closing environmental liabilities, Montana Power agreed to indemnify the purchaser from these pre-closing environmental liabilities, including a limited indemnity obligation for losses arising from required remediation of pre-closing environmental conditions, whether known or unknown at the closing, limited to:

- 50 percent of the loss. (Our share of this indemnity obligation at the Colstrip Project is limited to our pro-rata share of this 50 percent based on our pre-sale ownership share.)
- A two-year period after closing for unknown conditions. The indemnity for required remediation of pre-closing conditions known at the time of the closing continues indefinitely.
- An aggregate amount no greater than 10 percent of the purchase price paid for the assets.

Montana Power has received claim notices related to this indemnity obligation. Based on available information, we do not expect this indemnity claim on the indemnity obligation to have a material adverse effect on our combined financial position, results of operations, or cash flows.

Cash Proceeds

At December 31, 1999, we recorded a regulatory liability and related deferred income tax to reflect the generation sale proceeds in excess of book value. The Montana Power's liability, which was determined in the Tier II docket, is approximately $250,000,000 before income taxes. This liability represents a deferral of the gain on the generation sale and nothing has been reflected in the Statement of Income.

As part of our Tier II filing, we deducted from the regulatory liabilities approximately $15,000,000 of other after-tax generation-related transition costs and approximately $65,600,000 of regulatory asset transition costs. The other generation-related transition costs consist mainly of environmental costs and costs to retire debt. The regulatory asset transition costs consist mainly of capitalized conservation costs and carrying charges associated with Colstrip Unit 3.

Montana Power used a portion of the net cash proceeds received (excluding the proceeds in excess of book value) to purchase treasury shares of its common stock, to reduce debt, and to fund projects involving expansion of Touch America, a wholly owned subsidiary of Montana Power.

NOTE 3 - INCOME TAX EXPENSE

Income before income taxes for the years ended December 31, 2001 and 2000 was as follows:

	2001	2000
	(Thousands of Dollars)	
United States	$ (47,273)	$ (4,173)
Canada	37	237
	$ (47,236)	$ (3,936)

Income tax benefit as shown in the Statement of Income consists of the following components:

	2001	2000
	(Thousands of Dollars)	
Current		
United States	$ (16,101)	$ 6,706
Canada	38	16
State	4,077	(861)
	(11,986)	5,861
Deferred		
United States	7,298	(20,448)
State	373	(1,747)
	7,671	(22,195)
	$ (4,315)	$ (16,334)

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The provision (benefit) for income taxes differs from the amount of income tax determined by applying the applicable U. S. statutory federal rate to pretax income as a result of the following differences:

	2001	2000
	(Thousands of Dollars)	
Computed "expected" income tax benefit	$ (16,533)	$ (1,378)
Adjustments for tax effects of:		
Tax credits	(445)	(167)
State income tax, net.	4,560	(4,734)
Reversal of utility book/tax Depreciation	4,473	4,119
Other	3,630	(14,174)
Actual income tax benefit	$ (4,315)	$ (16,334)

Under Montana regulations, certain tax benefits flow through to customers on a basis consistent with the accelerated deduction of expenses for income tax purposes. As such, when these expenses are recognized for financial reporting purposes, there is not an offsetting tax savings. During periods of income, our utility's effective tax rate is higher than the statutory rate due to this timing difference. During periods of losses, tax benefits will appear lower than expected.

Deferred tax liabilities (assets) are comprised of the following at December 31:

	2001	2000
	(Thousands of Dollars)	
Plant related	$ 198,104	$ 221,632
Other	37,070	36,063
Gross deferred tax liabilities	235,174	257,695
Amortization of gain on sale/leaseback	(3,801)	(4,681)
Investment tax credit amortization	(8,265)	(14,056)
Other	(163,866)	(154,322)
Gross deferred tax assets	(175,932)	(173,059)
Net deferred tax liabilities	$ 59,242	$ 84,636

The change in net deferred tax liabilities differs from current year deferred tax expense as a result of the following:

	Thousands of Dollars
Change in deferred tax............................	$ (25,394)
Regulatory assets related to income taxes...........	27,678
Benefit restoration plan equity adjustment..........	1,022
Pension plan equity adjustment.....................	5,904
Amortization of investment tax credits.............	(445)
Transfer of MSC balance to MPC.....................	(1,094)
Deferred tax expense.............................	$ 7,671

NOTE 4 - PREFERRED STOCK

At December 31, 2001, Montana Power had 5,000,000 authorized shares of preferred stock. Montana Power's preferred stock is in three series as detailed in the following table:

Series	Stated and Liquidation Price*	Shares Issued and Outstanding		Thousands of Dollars	
		2001	2000	2001	2000
$6.875	$100	360,800	360,800	$36,080	$36,080
6.00	100	159,589	159,589	15,959	15,959
4.20	100	60,000	60,000	6,025	6,025
Discount		-	-	(410)	(410)
		580,389	580,389	$57,654	$57,654

*Plus accumulated dividends.

At a special meeting of Montana Power shareholders held on September 21, 2001, shareholders representing more than two-thirds of Montana Power's outstanding common stock approved (among others) the following proposals:

- Holders of Preferred Stock, $6.875 Series, of Montana Power will receive one share of Touch America Holdings, Inc. Preferred Stock, $6.875 Series, for each share of Montana Power Preferred Stock.
- The redemption of Montana Power's outstanding Preferred Stock, $4.20 Series, and Preferred Stock, $6.00 Series.

Responsibility for the preferred stock has reverted to Touch America with the February 15, 2002 sale of the utility to NorthWestern.

NOTE 5 - COMMON STOCK

❑ **SHARE REPURCHASE PROGRAM**

In 1998, the Board of Directors authorized a share repurchase program over the next five years to repurchase up to 20,000,000 shares, (approximately 18 percent of our then-outstanding common stock) on the open market or in privately negotiated transactions. As of December 31, 2001, we had 103,774,500 common shares outstanding. The number of shares to be purchased and the timing of the purchases will be based on the level of cash balances, general business conditions, and other factors, including alternative investment opportunities. As of December 31, 2001, we had acquired 6,616,000 shares of common stock at an average cost per share of approximately $31.085. We have shown the total cost of $205,656,000 as "Reacquired Capital Stock" on the Comparative Balance Sheet.

❑ **SHAREHOLDER PROTECTION RIGHTS PLAN**

We have a Shareholder Protection Rights Plan (SPRP) that provides one preferred share purchase right on each outstanding common share. Each purchase right entitles the registered holder, upon the occurrence of certain events, to purchase from us one one-hundredth of a share of Participating Preferred Shares, A Series, without par value. If it should become exercisable, each purchase right would have economic terms similar to one share of common stock. The purchase rights trade with the underlying shares and will, except under certain circumstances described in the SPRP, expire on June 6, 2009, unless redeemed earlier or exchanged by us.

❑ DIVIDEND REINVESTMENT AND STOCK PURCHASE PLAN

Our Dividend Reinvestment and Stock Purchase Plan permits participants to: (a) acquire additional shares of common stock through the reinvestment of dividends on all or any specified number of common and/or preferred shares registered in their own names, or through optional cash payments of up to $60,000 per year; and (b) deposit common and preferred stock certificates into their Plan accounts for safekeeping. It also allows for other interested investors (residents of certain states) to make initial purchases of its common shares with a minimum of $100 and a maximum of $60,000 per year.

In conjunction with the divestiture of our energy businesses and our transition to a telecommunications enterprise, our Board of Directors voted in October 2000 to eliminate the dividend payment on our common stock effective the first quarter 2001. The final quarterly dividend on our common stock was $0.20 per share, payable on November 1, 2000. The Board's decision did not affect dividends on our preferred stock.

❑ RETIREMENT SAVINGS PLAN

We have a 401(k) Retirement Savings Plan that covers eligible employees. We contribute, on behalf of the employee, a matching percentage of the amount contributed to the Plan by the employee. In 1990, we borrowed $40,000,000 at an interest rate of 9.2 percent to be repaid in equal annual installments over 15 years. The proceeds of the loan were lent on similar terms to the Plan Trustee, which used the proceeds to purchase 3,844,594 shares of our common stock. Shares acquired with loan proceeds are allocated monthly to Plan participants to help meet the Company's matching obligation. The loan, which is reflected as long-term debt, is offset by a similar amount in common shareholders' equity as unallocated stock. Our contributions plus the dividends on the shares held under the Plan are used to meet principal and interest payments on the loan with the Plan Trustee. As principal payments on the loan are made, long-term debt and the offset in common shareholders' equity are both reduced. At December 31, 2001, 3,012,646 shares had been allocated to the participants' accounts. We recognize expense for the Plan using the Shares Allocated Method, and the pretax expense was $3,385,000 and $2,570,000 for 2001 and 2000, respectively.

On February 15, 2002, Montana Power retired the ESOP notes. For more information regarding the ESOP notes, see Note 7, "Long-Term Debt."

The ESOP Plan was transferred to Touch America prior to the sale of the utility business to NorthWestern. The utility no longer maintains an employee stock ownership plan.

❑ LONG-TERM INCENTIVE PLAN

Under the Long-Term Incentive Plan, we have issued options to our employees. Options issued to employees are not reflected in balance sheet accounts until exercised, at which time: (1) authorized, but un-issued shares are issued to the employee; (2) the capital stock account is credited with the proceeds; and (3) no charges or credits to income are made.

Options were granted at the average of the high and low prices as reported on the New York Stock Exchange composite tape on the date granted and expire ten years from that date.

Option activity is summarized below:

	2001		2000	
	Shares	Wtd Avg Exercise Price	Shares	Wtd Avg Exercise Price
Outstanding, beginning of year	4,076,244	$28.43	3,280,325	$25.63
Granted	35,500	17.38	1,199,545	34.36
Exercised ..	32,984	13.49	149,834	17.07
Cancelled ..	1,051,313	27.75	253,792	26.88
Outstanding, end of year	3,027,447	$28.70	4,076,244	$28.43

Shares under option at December 31, 2001, are summarized below:

	Options Outstanding			Options Exercisable	
Exercise Price Range	Shares	Wtd Avg Exercise Price	Wtd Avg Exercise Life	Shares	Wtd Avg Exercise Price
$6.45	6,000	$ 6.45	10 yrs	-	$ -
$10.73 to $14.29	154,725	11.11	4 yrs	148,725	11.08
$18.00 to $24.66	399,929	19.60	7 yrs	317,446	18.62
$26.53 to $32.50	1,689,863	28.72	8 yrs	1,194,039	27.67
$35.36 to $38.69	776,930	37.00	8 yrs	394,930	35.36
	3,027,447			2,055,140	

As permitted by SFAS No. 123, "Accounting for Stock-Based Compensation," we have elected to follow Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25), and related interpretations in accounting for our employee stock options. Under APB 25, because the exercise price of the employee stock options equals the market price of the underlying stock on the date of grant, no compensation expense is recognized. Disclosure of pro-forma information regarding net income is required by SFAS No. 123. This information has been determined as if we had accounted for our employee stock options under the fair value method of that statement. The weighted-average fair value of options granted in 2001 and 2000 was $10.23 and $16.35 per share, respectively. We employed the binomial option-pricing model to estimate the fair value of each option grant on the date of grant. We used the following weighted-average assumptions for grants in 2001 and 2000, respectively: (1) risk-free interest rate of 5.07 percent and 6.05 percent; (2) expected life of 7.0 years and 6.2 years; (3) expected volatility of 51.00 percent and 42.00 percent; and (4) a dividend yield of zero percent for both years. Had we elected to use SFAS No. 123, compensation expense would have increased $10,904,000 in 2001 and $11,827,000 in 2000. The 2001 and 2000 pro forma net income after preferred dividends would be $5,015,000 and $188,632,000, respectively.

NOTE 6 - COMPANY OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUST

We established Montana Power Capital I (Trust) as a wholly owned business trust to issue common and preferred securities and hold Junior Subordinated Deferrable Interest Debentures (Subordinated Debentures) that we issue. At December 31, 2001 and 2000, the Trust had issued 2,600,000 units of 8.45 percent Cumulative Quarterly Income Preferred Securities, Series A (QUIPS). Holders of the QUIPS are entitled to receive quarterly distributions at an annual rate of 8.45 percent of the liquidation preference value of $25 per security. The sole asset of the Trust is $67,000,000 of our Subordinated Debentures, 8.45 percent Series due 2036. The Trust will use interest payments received on the Subordinated Debentures that it holds to make the quarterly cash distributions on the QUIPS. The QUIPS' $65,000,000 liquidation value is included with "Other Long Term Debt" on the Comparative Balance Sheet.

Since November 6, 2001, we can wholly redeem the Subordinated Debentures at any time, or partially redeem the Subordinated Debentures from time to time. Upon repayment of the Subordinated Debentures at maturity or early redemption, the Trust Securities must be redeemed. In addition, we can terminate the Trust at any time and cause the pro rata distribution of the Subordinated Debentures to the holders of the Trust Securities.

Besides our obligations under the Subordinated Debentures, we have agreed to certain Back-up Undertakings. We have guaranteed, on a subordinated basis, payment of distributions on the Trust Securities, to the extent the Trust has funds available to pay such distributions. We also have agreed to pay all of the expenses of the Trust. Considered together with the Subordinated Debentures, the Back-up Undertakings constitute a full and unconditional guarantee of the Trust's obligations under the QUIPS. We are the owner of all the common securities of the Trust, which constitute 3 percent of the aggregate liquidation amount of all the Trust Securities.

NOTE 7 - LONG-TERM DEBT

The Mortgage and Deed of Trust (Mortgage) imposes a first mortgage lien on all physical properties owned, exclusive of subsidiary company assets and certain property and assets specifically excepted. The obligations collateralized are First Mortgage Bonds, including those First Mortgage Bonds designated as Secured Medium-Term Notes (MTNs) and those securing Pollution Control Revenue Bonds.

Long-term debt consists of the following:

	December 31, 2001	December 31, 2000
	(Thousands of Dollars)	
First Mortgage Bonds:		
7% series, due 2005	$ 5,386	$ 5,386
7.30% series, due 2006	150,000	-
8 1/4% series, due 2007	365	365
8.95% series, due 2022	1,446	1,446
Secured Medium-Term Notes- maturing 2003-2008 7.20%-8.11%...........	28,000	28,000
Pollution Control Revenue Bonds:		
City of Forsyth, Montana		
6 1/8% series, due 2023..................	90,205	90,205
5.90% series, due 2023..................	80,000	80,000
Unsecured Medium-Term Notes Series B- maturing 2001-2026 7.20%-8.11%	40,000	100,000
ESOP Notes Payable - 9.20%, due 2004.........	12,666	16,197
8.45% QUIPS................................	65,000	65,000
Unamortized Discount and Premium............	(3,211)	(2,444)
	$469,857	$384,155

On November 27, 2001, we issued $150,000,000 of our 7.3 percent series First Mortgage Bonds (Bonds) due December 1, 2006. The net proceeds from the sale of the bonds were used to repay outstanding short-term debt and for general corporate purposes. In addition, we retired the 9.20 percent ESOP notes on February 15, 2002 with a portion of the proceeds.

On April 6, 2001, we retired $60,000,000 of our variable rate Series B Unsecured Medium Term Notes at maturity.

Scheduled debt repayments on the long-term debt outstanding at December 31, 2001, amount to: $12,666,000 in 2002; $15,000,000 in 2003; $5,386,000 in 2005; $165,000,000 in 2006; and $271,805,000 thereafter.

NOTE 8 - SHORT-TERM BORROWING

Our committed and uncommitted credit lines expired at the end of November 2001 and were not renewed by December 31, 2001. On November 21, 2001, Montana Power issued $150,000,000 in First Mortgage Bonds and used the proceeds from the bonds to repay the $60,000,000 balance outstanding under committed credit line, repay short-term borrowings, and repay an intercompany loan between Montana Power and Entech. The remaining balance was used for existing cash requirements and to redeem our ESOP notes. At December 31, 2001, we had no outstanding short-term borrowing.

At December 31, 2000, we had outstanding notes payable to banks for $75,000,000 at a weighted average annual interest rate of 8.05 percent. Of those outstanding notes, $25,000,000 were issued from our committed lines of credit and the other $50,000,000 from our uncommitted lines of credit.

NOTE 9 - RETIREMENT PLANS

Montana Power maintains trusteed, noncontributory retirement plans covering substantially all of our employees. Prior to 1998, our retirement benefits were based on salary, years of service, and social security integration levels. In 1998, we amended our retirement plan's benefit provisions. Our retirement benefits are now based on salary, age, and years of service. Northwestern has agreed to assume certain retirement plans and participants and maintain such plans or equivalent plans for a period of two years.

Our plan assets consist primarily of domestic and foreign corporate stocks, domestic corporate bonds, and United States Government securities.

We also have an unfunded, nonqualified benefit plan for senior management executives and directors. In December 1998, we froze the benefits earned and curtailed the plan. We own life insurance policies, the cash value/death benefit of which is intended to finance this plan.

As a result of the sale of our electric generating assets to PPL Montana, 454 participants related to electric generation operations were curtailed from the retirement plan and approximately $22,700,000 in assets were transferred from the retirement plan trust in December 1999. Pursuant to the agreement, when the calculation was finalized in February 2000, approximately $3,200,000 of additional assets were transferred to the PPL trust. In accordance with SFAS 88, we calculated a curtailment gain of approximately $4,100,000 and a settlement gain of approximately $7,800,000 in 1999. Due to regulatory accounting treatment, the gains were recorded as regulatory liabilities or offsets to regulatory assets, resulting in no income statement impact.

We offered a Special Retirement Program (SRP) to certain eligible employees during 2000. The SFAS 88 special termination charge resulting from 201 utility participants electing the SRP amounted to approximately $9,814,000. Due to regulatory accounting treatment, the expense was recorded as regulatory liabilities or offsets to regulatory assets, resulting in no income statement impact.

We also provide certain health care and life insurance benefits for eligible retired employees. In 1994, we established a pre-funding plan for postretirement benefits for utility employees retiring after January 1,1993. The plan assets consist primarily of domestic and foreign corporate stocks, domestic corporate bonds, and United States Government securities. The PSC allows us to include in rates all utility Other Postretirement Benefits costs on the accrual basis provided by SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions."

We also have a voluntary retirement savings plan in conjunction with our retirement plans. Through October 30, 2001, Montana Power contributed a matching percentage comprised of shares of Montana Power stock from a leveraged Employee Stock Ownership Plan (ESOP) arrangement and Montana Power shares purchased on the open market. Beginning November 1, 2002, we make cash contributions matching employee contributions up to 4 percent of their salaries. For costs associated with these plans and for information about the transfer of the ESOP Plan to Touch America, see Note 5, "Common Stock."

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The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of plan assets over the two-year period ending December 31, 2001, and a statement of the funded status as of December 31 of both years:

	Pension Benefits		Other Benefits	
	2001	2000	2001	2000
	(Thousands of Dollars)			
Change in benefit obligation:				
Benefit obligation at January 1.	$ 235,515	$ 197,333	$ 23,168	$ 18,918
Service cost on benefits earned.	3,676	4,090	420	430
Interest cost on projected benefit obligation............	16,992	15,893	1,851	1,561
Plan amendments.................	1,717	7,578	-	-
Assumption changes..............	-	5,859	-	-
Actuarial (gain)/loss...........	24,909	(4,988)	3,598	4,920
Adjustments for liability transfers.....................	14,072	11,630	(324)	-
Special termination benefits....	-	9,814	-	-
Gross benefits paid.............	(16,488)	(11,694)	(4,688)	(2,661)
Benefit obligation at December 31..................	$ 280,393	$ 235,515	$ 24,025	$ 23,168
Change in plan assets:				
Fair value of plan assets at January 1....................	$ 223,921	$ 230,606	$ 9,706	$ 9,916
Actual return/(loss) on plan assets.......................	(4,917)	(4,955)	107	329
Employer contributions..........	1,834	1,818	746	2,122
Acquisitions/divestitures.......	-	(3,200)	-	-
Assets allocated (to)/from related companies............	10,793	11,346	-	-
Gross benefits paid.............	(16,488)	(11,694)	(4,688)	(2,661)
Fair value of plan assets at December 31..................	$ 215,143	$ 223,921	$ 5,871	$ 9,706
Reconciliation of funded status:				
Funded status at end of year....	$ (65,250)	$ (11,594)	$ (18,153)	$ (13,461)
Unrecognized net:				
Actuarial gain................	24,642	(22,707)	2,855	(97)
Prior service cost............	20,459	21,295	1,248	1,459
Transition obligation.........	(129)	(196)	8,721	10,034
Acquisitions/divestitures.....	3,615	-	-	-
Net amount recognized at December 31................	$ (16,663)	$ (13,202)	$ (5,329)	$ (2,065)

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The following table provides the amounts recognized in the statement of financial position as of December 31:

	Pension Benefits		Other Benefits	
	2001	2000	2001	2000
	(Thousands of Dollars)			
Prepaid benefit cost	$ 2,170	$ 11,028	$ -	$ -
Accrued benefit cost	(18,833)	(24,230)	(5,329)	(2,065)
Additional minimum liability	(40,374)	(2,594)	-	-
Intangible asset	21,367		-	-
Regulatory asset - pension plan	14,990	-	-	-
Accum. other comprehensive inc.	4,017	2,594	-	-
Net amount recognized at December 31	$ (16,663)	$ (13,202)	$ (5,329)	$ (2,065)

The following tables provide the components of net periodic benefit cost for the pension and other postretirement benefit plans, portions of which have been deferred or capitalized, for fiscal years 2001, 2000, and 1999:

	Pension Benefits	
	2001	2000
	(Thousands of Dollars)	
Service cost on benefits earned	$ 3,676	$ 4,090
Interest cost on projected benefit obligation	16,992	15,893
Expected return on plan assets	(17,921)	(20,273)
Amortization of:		
Transition obligation	(47)	(49)
Prior service cost	1,947	1,607
Actuarial gain	67	(2,830)
Net periodic benefit cost (credit)	4,714	(1,562)
Special termination benefit charge	-	9,814
Curtailment (gain)/loss	-	-
Settlement gain	-	-
Net periodic benefit cost (credit) after curtailments and settlements	$ 4,714	$ 8,252

	Other Benefits 2001	Other Benefits 2000
	(Thousands of Dollars)	
Service cost on benefits earned	$ 420	$ 430
Interest cost on projected benefit obligation	1,851	1,561
Expected return on plan assets	(706)	(819)
Amortization of:		
Transition obligation	792	837
Prior service cost	138	146
Actuarial gain	-	(128)
Net periodic benefit cost (credit)	2,495	2,027
Curtailment (gain)/loss	-	-
Net periodic benefit cost (credit) after curtailments and settlements	$ 2,495	$ 2,027

In 2001, funding for pension costs was less than SFAS No. 87, "Employers Accounting for Pensions," pension expense by $3,138,000. In 2000, pension costs exceeded SFAS No. 87 pension expense by $3,078,000. The PSC allows recovery for the funding of pension costs through rates. Any differences between funding and expense are deferred for recognition in future periods. At December 31, 2001, the regulatory liability was $7,487,000.

The following assumptions were used in the determination of actuarial present values of the projected benefit obligations:

	Pension Benefits 2001	Pension Benefits 2000	Other Benefits 2001	Other Benefits 2000
Weighted average assumptions as of December 31:				
Discount rate	7.00%	7.50%	7.00%	7.50%
Expected return on plan assets	9.00%	9.00%	9.00%	9.00%
Rate of compensation increase	4.40%	4.40%	4.40%	4.40%

Assumed health care costs trend rates have a significant effect on the amounts reported for the health care plans. A change of 1 percent in assumed health care cost trend rates would have the following effects:

(Thousands of Dollars)	1% Increase	1% Decrease
Effect on the total of service and interest cost components of net periodic post-retirement health care benefit cost	$ 95	$ (82)
Effect on the health care component of the accumulated postretirement benefit obligation	687	(604)

The assumed 2001 health care cost trend rates used to measure the expected cost of benefits covered by the plans is 9.00 percent. The trend rate decreases through 2007 to 5.50 percent.

NOTE 10 - CONTINGENCIES

- **KERR PROJECT**

A FERC order that preceded the sale of the Kerr Project required Montana Power to implement a plan to mitigate the effect of the Kerr Project operations on fish, wildlife, and habitat. To implement this plan, Montana Power was required to make payments of approximately $135,000,000 between 1985 and 2020, the term during which we would have been the licensee. The net present value of the total payments, assuming a 9.5 percent annual discount rate, was approximately $57,000,000, an amount we recognized as license costs in plant and long-term debt on the Comparative Balance Sheet in 1997. In the sale of the Kerr Project, the purchaser of the electric generating assets assumed the obligation to make post-closing license compliance payments.

In December 1998 and January 1999, Montana Power requested a review by the United States Court of Appeals for the District of Columbia Circuit of this order and another FERC order which included the United States Department of Interior's conditions. In December 2000, FERC issued an order approving a settlement among the parties. On February 15, 2001, the Circuit Court dismissed the petitions for review. Consequently, the approximately $24,000,000 that Montana Power paid into escrow in 2000 was released to the Confederated Salish and Kootenai Tribes (Tribes) to be used in accordance with the terms of the settlement. We have also transferred 669 acres of land on the Flathead Indian Reservation to the Tribes. With the payment and the transfer of land, we have fulfilled our obligations under the terms of this settlement. Because PPL Montana, the purchaser, assumed the obligation in excess of $24,000,000, the basis in the properties sold decreased and the regulatory liability associated with the deferred gain on the sale increased accordingly.

- **LONG-TERM POWER SUPPLY AGREEMENTS**

Long-term power supply agreements, primarily an agreement with a large industrial customer, exposed us to losses and potential future losses mainly because of unusually high electric energy market prices. To eliminate our exposure to expected future losses through December 2002 when the agreement with that customer terminated, we executed a termination agreement effective June 30, 2001. Under the termination agreement, we made a one-time payment of $62,500,000 to the customer and ended our obligations under this power supply agreement. We recorded a pretax loss of $62,500,000, or approximately $37,900,000 after income taxes, in the second quarter 2001. Prior to the termination agreement, we recorded pretax losses associated with the power supply agreement of approximately $2,500,000 in the first quarter 2001, and $22,500,000 in the second quarter 2001, and approximately $16,200,000 for the year ended December 31, 2000.

❑ CLASS ACTION LAWSUIT

On August 16, 2001, eight individuals filed a lawsuit in Montana State District Court, naming Montana Power, eleven of its current Board of Directors, three officers of both Touch America and Montana Power, and PPL Montana as defendants. In their complaint, the plaintiffs allege that Montana Power and its directors and officers had a legal obligation and a fiduciary duty to obtain shareholder approval before the sale of our former electric generation assets to PPL Montana. On September 14, 2001, the complaint was amended to add one other current officer of Touch America, one other current officer of Montana Power, and our investment banking consultants as additional defendants. As previously reported, Montana Power completed the sale of the electric generation assets to PPL Montana in December 1999. The plaintiffs further allege that because Montana Power shareholders did not vote, the sale of the generation assets is void and PPL Montana is holding these assets in constructive trust for the shareholders.

Alternatively, the plaintiffs allege that Montana Power shareholders should have been allowed to vote on the sale of the generation assets and, if an appropriate majority vote was obtained in favor of the sale, the shareholders should have been given dissenters' rights. The plaintiffs also make various claims of breaches of duty and negligence against the Board of Directors and the individual officers. The plaintiffs have indicated that they will seek court approval to proceed with this suit as a class action.

It is Montana Power's position that Montana Power and its former directors and officers, and one current officer, have fully complied with their statutory and fiduciary duties. Accordingly, Montana Power is defending the suit vigorously. Montana Power filed a motion to dismiss the complaint in late November 2001. At this early stage, however, we cannot predict the ultimate outcome of this matter or how it may affect our combined financial position, results of operations, or cash flows.

❑ MISCELLANEOUS

We are parties to various other legal claims, actions, and complaints arising in the ordinary course of business. We do not expect the conclusion of any of these matters to have a material adverse effect on our combined financial position, results of operations, or cash flows.

NOTE 11 - COMMITMENTS

❑ PURCHASE COMMITMENTS

Electric Utility

The Public Utilities Regulatory Policies Act (PURPA) requires a public utility to purchase power from QFs at a rate equal to what it would pay to generate or purchase power. These QFs are power production or co-generation facilities that meet size, fuel use, ownership, and operating and efficiency criteria specified by PURPA. The electric utility has 15 long-term QF contracts with expiration terms ranging from 2003 through 2032 that require us to make payments for energy capacity and energy received at prices established by the PSC. Three contracts account for 96 percent of the 101 MWs of capacity provided by these facilities. Montana's 1997 Electric Act designates above-market portion of the QF costs as Competitive Transition

Costs (CTCs) and allows for their recovery. For more information about CTCs, see Note 2, "Deregulation, Regulatory Matters, and 1999 Sale of Electric Generating Assets".

Montana's 1997 Electric Act also designated Montana Power as the default power supplier for those customers who had not chosen another supplier by July 1, 2002. To fulfill that obligation, there was included in the Asset Purchase Agreement with PPL Montana, dated as of October 31, 1998 and amended June 29, 1999 and October 29, 1999, two Wholesale Transition Service Agreements (WTSAs), effective December 17, 1999. One agreement terminated at December 31, 2001. The other agreement continues to commit us to purchase through June 2002 any power requirements remaining after having received power from the QFs and Milltown Dam, and prices the power purchased from PPL Montana at a market index, with a monthly floor and an annual cap.

In its 2001 session, the Montana Legislature passed House Bill 474, which extends the transition period of electric deregulation in Montana from July 1, 2002 to June 30 2007 and, therefore, our obligation as a default supplier through June 30, 2007. We entered into three power purchase agreements in October 2001 that enable us to satisfy, in part, our "Default Supply" obligation. These agreements commit us to purchase a total of 561 MWs per hour during peak hours and 411 MWs per hour during the off-peak hours in the first year of the extended transition period. In the remaining years of the transition period, these agreements also obligate us to purchase 450 MWs per hour during the peak hours and 300 MWs per hour during the off-peak hours. These purchases are included in the "Default Supply Portfolio" filing with the PSC (Docket No.D2001.10.144) dated October 29, 2001. House Bill 474 also provides for the complete recovery in rates of the default supplier's costs that are prudently incurred to supply electric energy. For more information about electric deregulation, see Note 2, "Deregulation, Regulatory Matters, and 1999 Sale of Electric Generating Assets," in the "Electric Deregulation" section.

Natural Gas Utility

Since 1998, because of uncertainty about the number and timing of customers who could choose another natural gas supplier under the provisions of Montana's 1997 Natural Gas Act, Montana Power entered primarily into one-year take-or-pay contracts with Montana natural gas producers. We currently have six of these contracts, five of which expire in 2002, and one in 2006. After July 1, 2002, we are not obligated to supply natural gas to those who do not choose another supplier. We have a request before the PSC to designate us as the natural gas default supplier for the five-year period beyond July 1, 2002. Upon such designation, we will secure additional supply contracts to meet the needs of our customers.

Contractual Payments and Present Value

Total payments under all of these contracts for the prior three years were as follows:

	Electric	**Natural Gas**	**Total**
	(Thousands of Dollars)		
2001	$263,924	$ 16,764	$280,688
2000	272,075	7,101	279,176
1999	61,274	4,069	65,343

Under the above agreements, the present value of future minimum payments, at a discount rate of 3.615 percent, is as follows:

	Electric	**Natural Gas**	**Total**
	(Thousands of Dollars)		
2002	$103,724	$ 8,871	$112,595
2003	118,985	613	119,598
2004	104,289	612	104,901
2005	100,677	593	101,270
2006	87,723	566	88,289
Remainder	241,009	-	241,009
	$756,407	$11,255	$767,662

❑ **LEASE COMMITMENTS**

On September 24, 1997, Montana Power entered into a seven-year operating lease with a banking institution - for an automated meter reading system - with annual payments of approximately $2,400,000. This lease was terminated by NorthWestern on February 15, 2002. We have no other material minimum operating lease payments and capitalized leases are not material.

Rental expense for the prior two years was $9,700,000 for 2001, $6,800,000 for 2000, and $56,316,000 for 1999.

NOTE 12 - NEW ACCOUNTING PRONOUNCEMENTS

❑ **SFAS NOS. 141, 142, 143, AND 144**

In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, "Business Combinations." SFAS No. 141 eliminates the use of the pooling of interests method of accounting, and requires that all mergers and acquisitions be accounted for using the purchase method of accounting. SFAS No. 141 also establishes specific criteria for the recognition of intangible assets separately from goodwill and adds new disclosure requirements. This statement is effective for all mergers and acquisitions initiated after June 30, 2001. Adoption of this pronouncement is not expected to have a material impact on our financial position, results of operations, or cash flows.

In June 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangibles." The amortization provisions of SFAS No. 142 apply to goodwill and other intangibles acquired after June 30, 2001. For goodwill and other intangible assets acquired prior to July 1, 2001, adoption of SFAS No. 142 is required for fiscal years beginning after December 15, 2001. SFAS No. 142 primarily addresses the accounting for goodwill and intangible assets subsequent to their initial recognition. The provisions of SFAS 142:

- prohibit the amortization of goodwill and indefinite-lived intangible assets;
- require that reporting units be identified for the purpose of assessing potential future impairments of goodwill;
- remove the forty-year limitation on the amortization period of intangible assets that have finite lives; and

- prohibit amortization of the excess of cost over the underlying equity in the net assets of an equity-method investee that is recognized as goodwill.

In addition, SFAS No. 142 requires that goodwill be tested annually for impairment - and in interim periods if certain events occur indicating that the carrying value of goodwill and/or indefinite-lived intangible assets may be impaired - using a two-step process. The first step is to identify a potential impairment and, in transition, this step must be measured as of the beginning of the fiscal year. However, a company has six months from the date of adoption to complete the first step. The second step of the goodwill impairment test measures the amount of the impairment loss (measured as of the beginning of the year of adoption), if any, and must be completed by the end of the fiscal year. Intangible assets deemed to have an indefinite life will be tested for impairment using a one-step process which compares the fair value to the carrying amount of the asset as of the beginning of the fiscal year, and pursuant to the requirements of SFAS 142 will be completed during the first quarter of 2002. Any impairment loss resulting from the transitional impairment tests will be reflected as the cumulative effect of a change in accounting principle in the first quarter 2002. Adoption of this pronouncement is not expected to have a material impact on our financial position, results of operations, or cash flows.

In June 2001, the FASB issued SFAS No. 143 "Accounting for Asset Retirement Obligations." SFAS No. 143 requires entities to record the fair value of a legal liability for an asset retirement obligation in the period it is incurred. The asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. This statement is effective for financial statements issued for fiscal years beginning after June 15, 2002. We are currently evaluating this pronouncement, but we do not expect it to have a material impact on our financial position, results of operations, or cash flows.

In August 2001, the FASB issued SFAS No. 144 "Accounting for the Impairment of Long-Lived Assets." SFAS No. 144 addresses financial accounting and reporting for the impairment or disposal of long-lived assets. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2001. Adoption of this pronouncement is not expected to have a material impact on our financial position, results of operations, or cash flows.

Sch. 19	MONTANA PLANT IN SERVICE - NATURAL GAS (INCLUDES CMP)			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1	**Intangible Plant**			
2	2301 Organization	$12,873	$12,873	0.00%
3	2302 Franchises and Consents	114,169	258,020	-55.75%
4	2303 Miscellaneous Intangible Plant	378,912	396,672	-4.48%
5	**Total Intangible Plant**	505,954	667,565	-24.21%
6				
7	**Underground Storage Plant**			
8	2350 Land and Land Rights	3,945,566	3,944,064	0.04%
9	2351 Structures and Improvements	2,545,210	2,729,021	-6.74%
10	2352 Wells	7,689,329	7,787,497	-1.26%
11	2353 Lines	5,895,936	6,593,845	-10.58%
12	2354 Compressor Station Equipment	7,315,999	7,114,168	2.84%
13	2355 Measuring & Regulating Equip.	1,762,740	1,715,655	2.74%
14	2356 Purification Equipment	223,171	223,171	0.00%
15	2357 Other Equipment	831,995	831,995	0.00%
16	**Total Underground Storage Plant**	30,209,946	30,939,416	-2.36%
17				
18	**Transmission Plant**			
19	2365 Rights of Way	5,360,470	5,276,289	1.60%
20	2366 Structures and Improvements	8,921,913	8,272,854	7.85%
21	2367 Mains	131,495,013	128,110,841	2.64%
22	2368 Compressor Station Equipment	18,088,263	16,522,666	9.48%
23	2369 Meas. & Reg. Station Equipment	9,742,609	9,096,923	7.10%
24	2370 Communication Equipment	66,875	66,875	0.00%
24	2371 Other Equipment	75,670	69,441	8.97%
25	**Total Transmission Plant**	173,750,813	167,415,889	3.78%
26				
27	**Distribution Plant**			
28	2374 Land and Land Rights	874,556	858,309	1.89%
29	2375 Structures and Improvements	71,404	213,859	-66.61%
30	2376 Mains	71,020,275	68,143,862	4.22%
31	2377 Compressor Station Equipment			
32	2378 M&R Station Equip.-General	2,013,139	2,037,883	-1.21%
33	2379 M&R Station Equip.-City Gate	-	337,497	-100.00%
34	2380 Services	52,122,462	52,021,516	0.19%
35	2381 Customers Meters and Regulators	17,286,010	16,458,262	5.03%
36	2382 Meter Installations	9,657,320	9,573,802	0.87%
37	2383 House Regulators			
38	2384 House Regulator Installations			
39	2385 M&R Station Equip.-Industrial	56,334	51,651	9.07%
40	2386 Other Prop. on Customers' Premises			
41	2387 Other Equipment	-	-	-
42	**Total Distribution Plant**	153,101,500	149,696,641	2.27%

Sch. 19	MONTANA PLANT IN SERVICE - NATURAL GAS (INCLUDES CMP)			
	Account Number & Title	This Year Montana	Last Year Montana	% Change
1				
2	**General Plant**			
3	2389 Land and Land Rights	101,675	104,550	-2.75%
4	2390 Structures and Improvements	684,305	677,992	0.93%
5	2391 Office Furniture and Equipment	1,531,842	1,576,897	-2.86%
6	2392 Transportation Equipment	6,188,831	6,357,874	-2.66%
7	2393 Stores Equipment	10,804	11,710	-7.74%
8	2394 Tools, Shop & Garage Equipment	3,847,714	3,832,107	0.41%
9	2395 Laboratory Equipment	803,996	815,000	-1.35%
10	2396 Power Operated Equipment	1,615,214	1,693,402	-4.62%
11	2397 Communication Equipment	1,338,384	1,175,775	13.83%
12	2398 Miscellaneous Equipment	40,258	43,602	-7.67%
13	2399 Other Tangible Property		-	-
14	**Total General Plant**	16,163,023	16,288,909	-0.77%
15	**Total Gas Plant in Service**	373,731,236	365,008,420	2.39%
16				
17	4101 Gas Plant Allocated from Common	26,963,375	14,012,437	92.42%
18	2105 Gas Plant Held for Future Use	8,984	8,984	-
19	2107 Gas Construction Work in Progress	2,312,031	569,897	305.69%
20	2117 Gas in Underground Storage	42,379,908	40,695,109	4.14%
21				
22				
23	**Total Gas Plant**	$445,395,534	$420,294,847	5.97%

Sch. 20	MONTANA DEPRECIATION SUMMARY - NATURAL GAS (INCLUDES CMP)				
	Functional Plant Class	Montana Plant Cost	This Year Montana	Last Year Montana	Current Avg. Rate
1	**Accumulated Depreciation**				
2					
3	Production and Gathering			$0	0.00%
4					
5					
6	Underground Storage	30,939,416	13,820,819	12,965,688	2.67%
7					
8	Other Storage				
9					
10	Transmission	167,415,889	58,159,560	55,433,973	1.77%
11					
12	Distribution	149,701,324	55,798,034	51,595,412	3.09%
13					
14	General and Intangible	16,951,791	9,052,945	9,345,117	5.12%
15					
16	Common	14,012,437	7,737,725	3,114,332	5.38%
17					
18	**TOTAL DEPRECIATION**	$379,020,857	$144,569,083	$132,454,522	2.54%
19					
20					
21					
22					
23					

Sch. 21	MONTANA MATERIALS & SUPPLIES (ASSIGNED & ALLOCATED) - NATURAL GAS			
	Account Number & Title	This Year Cons. Utility	Last Year Montana	%Change
151	Fuel Stock			
152	Fuel Stock Expenses Undistributed			
153	Residuals			
154	Plant Materials & Operating Supplies			
	Assigned and Allocated to:			
	Operation & Maintenance			
	Construction			
	Storage Plant	$ 164,071	$ 187,009	-12.27%
	Transmission Plant	943,646	1,011,922	-6.75%
	Distribution Plant	831,499	904,820	-8.10%
155	Merchandise			
156	Other Materials & Supplies			
157	Nuclear Materials Held for Sale			
163	Stores Expense Undistributed			
TOTAL MATERIALS & SUPPLIES		$1,939,216	$2,103,751	-7.82%

Sch. 22

MONTANA REGULATORY CAPITAL STRUCTURE & COSTS - GAS

		% Capital Structure	% Cost Rate	Weighted Cost
1	**Commission Accepted - Most Recent 1/**			
2				
3	Docket Number: 2000.8.113			
4	Order Number : 6271c			
5				
6	Common Equity	45.00%	10.75%	4.84%
7	Preferred Stock	6.97%	6.40%	0.45%
8	QUIPs Preferred 2/	7.86%	8.54%	0.67%
9	Long Term Debt	40.17%	7.13%	2.86%
10	**TOTAL**	100.00%		8.82%
11				
12	**Actual at Year End**			
13				
14	Common Equity	37.26%	10.75%	4.01%
15	Preferred Stock	7.03%	6.40%	0.45%
16	QUIPS Preferred 2/	7.92%	8.54%	0.68%
17	Long Term Debt 3/	47.79%	7.68%	3.67%
18	**TOTAL**	100.00%		8.81%
19				
20	1/ Docket 2000.8.113, Order 6271c specifies the authorized capital structure and associated costs for			
21	the regulated gas utility effective May 8, 2001.			
22				
23	2/ The cost of the QUIPS securities is treated as tax deductible for income tax purposes.			
24	See footnote on Schedule 25.			
25				
26	3/ The cost rate cannot be tied directly to Schedule 24, which is presented on a consolidated basis.			

Sch. 23	STATEMENT OF CASH FLOWS (INCLUDES UNIT 4) - 1/			
	Description	This year	Last Year	% Change
1	Increase/(decrease) in Cash & Cash Equivalents:			
2	**Cash Flows from Operating Activities:**			
3	Net Income	$15,393,683	$199,490,689	-92.28%
4	Depreciation	55,281,111	48,266,339	14.53%
5	Amortization	94,914	94,939	-0.03%
6	Deferred Income Taxes - Net	(19,429,078)	(15,883,186)	-22.32%
7	Investment Tax Credit Adjustments - Net	(444,673)	(166,770)	-166.64%
8	Change in Operating Receivables - Net	231,253,843	(21,580,392)	1171.59%
9	Change in Materials, Supplies & Inventories - Net	599,764	(92,138)	750.94%
10	Change in Operating Payables & Accrued Liabilities - Net	(196,263,958)	(52,468,014)	-274.06%
11	Allowance for Funds Used During Construction (AFUDC)	(36,530)	(446,286)	91.81%
12	Change in Other Assets & Liabilities - Net	-	-	-
13	Other Operating Activities:			
14	Undistributed Earnings from Subsidiary Companies	(59,388,353)	(193,438,772)	69.30%
15	Amortization of Loss on Long-Term Sale of Power	-	-	-
16	Other (net)	(241,219,431)	4,975,607	-4948.04%
17	Change in Regulatory Assets	(3,089,595)	(15,464,321)	80.02%
18	Change in Regulatory Liabilities	269,133,676	36,517,739	636.99%
19	**Net Cash Provided by/(Used in) Operating Activities**	51,885,373	(10,194,566)	608.95%
20	**Cash Inflows/Outflows From Investment Activities:**			
21	Construction/Acquisition of Property, Plant and Equipment	(58,505,790)	(49,747,654)	-17.61%
22	(net of AFUDC & Capital Lease Related Acquisitions)			
23	Sale of Generation Assets	-	-	
24	Contributions In and Advances to Affiliates	-	(99,001,000)	-
25	Other Investing Activities:			
26	Miscellaneous Special Funds	(36,806)	473,237,760	-100.01%
27	**Net Cash Provided by/(Used in) Investing Activities**	(58,542,596)	324,489,106	-118.04%
28	**Cash Flows from Financing Activities:**			
29	Proceeds from Issuance of:			
30	Long-Term Debt	150,000,000	35,556,648	321.86%
31	Common Stock	467,115	2,445,313	-80.90%
32	Other: Manditorily Redeem. Pref. Securities of Sub. Trust			
33	Dividends from Subsidiaries	-	-	
34	Net Increase in Short-Term Debt	-	75,000,000	-
35	Other: Return of Subsidiary Capital			
36	Payment for Retirement of:			
37	Long-Term Debt	(64,297,988)	(297,868,964)	78.41%
38	Preferred Stock	-	-	-
39	Net Decrease in Short-Term Debt	(75,000,000)		
40	Dividends on Preferred Stock	(3,769,784)	(3,690,034)	-
41	Dividends on Common Stock	-	(62,426,418)	100.00%
42	Other Financing Activities (explained on attached page) 2/	-	(60,784,409)	100.00%
43	**Net Cash Provided by (Used in) Financing Activities**	7,399,343	(311,767,864)	102.37%
44				
45	**Net Increase/(Decrease) in Cash and Cash Equivalents**	742,120	2,526,676	-70.63%
46	**Cash and Cash Equivalents at Beginning of Year**	(4,538,779)	(7,065,455)	35.76%
47	**Cash and Cash Equivalents at End of Year**	($3,796,659)	($4,538,779)	16.35%
48				
49	1/ The cash balances on the 2001 and 2000 balance sheets include CMP, whereas the statement of			
50	cash flows does not.			
51				
52	2/ The amount listed on line 42 for 2000 is the amount paid to reacquire Common Stock.			

Sch. 24

LONG TERM DEBT 1/

Description	Issue Date	Maturity Date	Principal Amount	Net Proceeds	Outstanding Per Balance Sheet	Yield to Maturity	Annual Net Cost Inc. Prem./Disc.	Total Cost %
First Mortgage Bonds								
8.25% Series, Due 2007	12/05/91	02/01/07	55,000,000	54,550,100	364,966	8.260%	30,167	8.27%
8.95% Series, Due 2022	12/05/91	02/01/22	50,000,000	49,536,500	1,437,200	8.957%	129,979	9.04%
7.00% Series, Due 2005	03/01/93	03/01/05	50,000,000	49,375,000	5,370,355	7.075%	383,032	7.13%
7.30% Series, Due 2006	11/27/01	12/01/06	150,000,000	148,670,240	149,121,250	7.426%	11,324,552	7.59%
Total First Mortgage Bonds			$305,000,000	$302,131,840	$156,293,771		$11,867,730	7.59%
Pollution Control Bonds								
6-1/8% Series, Due 2023	06/30/93	05/01/23	$90,205,000	$88,199,743	$88,771,073	5.841%	$5,620,635	6.33%
5.90% Series, Due 2023	12/30/93	12/01/23	80,000,000	79,040,800	79,294,183	6.428%	4,834,215	6.10%
Total Pollution Control Bonds			$170,205,000	$167,240,543	$168,065,256		$10,454,850	6.22%
Other Long Term Debt								
Quarterly Income Preferred Securities, 8.45%, Series A (QUIPS) 2/	11/96	11/01	$ 65,000,000	$ 62,567,385	$ 65,000,000		$ 5,553,304	8.54%
Medium Term Notes-Secured Series	Various	Various	128,000,000	126,807,269	28,000,000		2,076,332	7.42%
Medium Term Notes-Unsecured Series B	Various	Various	115,000,000	113,851,197	39,832,471		3,069,288	7.71%
Cost Associated with Prior Debt Retirements	N/A	N/A	0	0	0		201,237	N/A
Total Other Long Term Debt			$308,000,000	$303,225,851	$132,832,471		$10,900,161	8.21%
TOTAL LONG TERM DEBT			$783,205,000	$772,598,234	$457,191,498		$33,222,741	7.27%

1/ Total Long-Term Debt does not include ESOP debt of $12,666,000, as ESOP debt is not used for rate making purposes.
Total Long-Term Debt does not include amounts due within 1 year - $ 0 at December 31, 2001.

2/ The Company believes and intends to take the position that the securities associated with the QUIPS issue will constitute indebtedness for United States federal income tax purposes. As such, the cost of QUIPS are deemed to be tax deductible. Since November 6, 2001, the Company has the right to wholly redeem the securities at any time, or partially redeem them from time to time.

Sch. 25

PREFERRED STOCK

	Series	Issue Date	Shares Issued	Par Value	Call Price	Net Proceeds	Cost of Money	Principal Outstanding	Annual Cost	Embedded Cost %
1										
2	$6.00 Series Cumulative	1929-1932	159,589	$100	$110.000	$15,958,900	6.00%	$15,958,900	$957,534	6.00%
3										
4	$4.20 Series Cumulative	May 1954	60,000	$100	$103.000	6,024,600	4.18%	6,024,600	252,000	4.18%
5										
6	$6.875 Series Cumulative 1/	Nov 1993	360,800	$100	$103.438	35,670,412	6.88%	35,670,412	2,480,500	6.95%
7										
8										
9										
10	**TOTAL PREFERRED STOCK**		580,389			$57,653,912	6.36%	$57,653,912	$3,690,034	6.40%
11										
12	1/ Not redeemable prior to November 1, 2003, at which point call price will decrease by .344 per year to equal 100.00 at November 1, 2013.									

Sch. 26

COMMON STOCK

	Avg. Number of Shares Outstanding 1/	Book Value Per Share 2/	Earnings Per Share	Dividends Per Share (Declared)	Retention Ratio	Market Price		Price/ Earnings Ratio
						High	Low	
January	103,743,534	$10.75				$26.50	$18.06	
February	103,755,534	10.90				22.22	17.55	
March	103,760,218	11.24	$0.58			18.20	13.05	
April	103,760,218	11.18				14.49	11.19	
May	103,773,500	11.22				16.75	12.75	
June	103,774,500	11.12	(0.11)			13.59	9.65	
July	103,774,500	11.09				11.48	9.45	
August	103,774,500	11.10				9.90	6.40	
September	103,774,500	10.87	(0.27)			7.15	5.07	
October	103,774,500	10.82				7.46	5.01	
November	103,774,500	10.79				5.40	3.95	
December	103,774,500	10.77	(0.09)			5.95	4.36	
TOTAL Year End	103,767,875	$10.77	$0.11	$0.00	100.00%	$5.75		52.3

1/ Monthly shares are actual shares outstanding at month-end. Total year-end shares are average shares for 2001.

2/ All Book Value Per Share amounts are based on actual shares and include unallocated stock held by Trustee for the Deferred Savings and Employee Ownership Plans.

Sch. 27

MONTANA EARNED RATE OF RETURN - GAS

	Description	This Year	Last Year	% Change
	Rate Base			
101	Plant in Service	$394,421,856	$369,531,253	6.74%
108	Accumulated Depreciation	(141,464,868)	(129,051,425)	-9.62%
Net Plant in Service		$252,956,988	$240,479,828	5.19%
	Additions:			
154, 156	Materials & Supplies	$3,753,108	$3,323,790	12.92%
165	Prepayments	0	0	0.00%
	Other Additions 3/	47,765,921	48,276,676	-1.06%
Total Additions		$51,519,029	$51,600,466	-0.16%
	Deductions:			
190	Accumulated Deferred Income Taxes 1/	$42,853,585	$35,461,385	20.85%
252	Customer Advances for Construction	3,963,639	3,263,784	21.44%
255	Accumulated Def. Investment Tax Credits	0	0	0.00%
	Other Deductions 4/	26,392,039	20,818,300	26.77%
Total Deductions		$73,209,263	$59,543,469	22.95%
Total Rate Base		$231,266,754	$232,536,825	-0.55%
Net Earnings		$8,244,875	$555,558	1384.07%
Rate of Return on Average Rate Base		3.565%	0.239%	1392.22%
Rate of Return on Average Equity 2/		-4.449%	-12.979%	65.72%
	Major Normalizing and Commission Ratemaking Adjustments			
	Rate Schedule Revenues	$1,699,621	$1,805,414	-5.86%
	Regulatory Asset Adjustments	(3,034,076)	0	0.00%
	Gain sharing on sale of Oil & Gas	23,750,872	32,549,128	-27.03%
	Non-Allowables:			
	Advertising	195,785	289,895	-32.46%
	Benefit Restoration Plan	461,374	156,456	194.89%
	Dues, Contributions, Other	5,370	2,442	119.90%
	Corporate Overhead	0	119,121	-100.00%
	Associated Income Taxes	(9,090,220)	(13,755,082)	33.91%
Total Adjustments		$13,988,726	$21,167,374	-33.91%
Revised Net Earnings		$22,233,601	$21,722,932	2.35%
Adjusted Rate of Return on Average Rate Base		9.614%	9.342%	2.91%
Adjusted Rate of Return on Average Equity 2/		11.943%	6.931%	72.31%

1/ Includes adjustments related to FAS 109.

2/ ROE calculation utilizes a average of four quarters common equity component applied to rate base for the denominator of the equations. The 2001 common equity component applied to rate base was 42.26%. An average was used to more accurately reflect 2001 common equity.

3/ Adjusted ROE includes $3,351,634 interest adjustment on Gain sharing of Oil & Gas sale proceeds in 2001.

Sch. 27 cont.

MONTANA EARNED RATE OF RETURN - GAS

Description	This Year	Last Year	% Change
Detail - Other Additions 3/			
FAS 109 Regulatory Asset	$10,746,874	$8,093,582	32.78%
Gas Stored Underground	33,652,078	38,669,601	-12.98%
Cost of Refinancing Debt	1,476,903	1,251,053	18.05%
1994 Severance Plan	0	59,099	-100.00%
1995 and 1996 Severance Plans	144,736	144,736	0.00%
1997 and 1998 Severance Plans	41,884	41,884	0.00%
1999 Severance Plan	59,151	0	100.00%
Division Centralization	16,721	16,721	0.00%
ORCOM Development Costs	298,706	0	100.00%
SAP Development Costs	1,328,868	0	100.00%
Total Other Additions	$47,765,921	$48,276,676	-1.06%
Detail - Other Deductions 4/			
Personal Injury and Property Damage	$1,005,101	$989,319	1.60%
Storage Gas Sales 2000 & 2001	2,957,062	0	100.00%
Gross Cash Requirements	3,928,429	1,298,377	202.56%
Met Life Refund	68,106	0	100.00%
Bond Refinancing CTC - GP	4,327,819	4,369,094	-0.94%
Bond Refinancing CTC - RA	13,776,242	13,915,459	-1.00%
USBC Gas	83,229	0	100.00%
Deferred Storage Gas Sales	246,051	246,051	0.00%
Total Other Deductions	$26,392,039	$20,818,300	26.77%

Sch. 28	MONTANA COMPOSITE STATISTICS - NATURAL GAS (INCLUDES CMP)		
		Description	Amount
1			
2		**Plant (Intrastate Only)**	
3			
4	101	Plant in Service (Includes Allocation from Common)	400,694,611
5	105	Plant Held for Future Use	8,984
6	107	Construction Work in Progress	2,312,031
7	117	Gas in Underground Storage	42,379,908
8	151-163	Materials & Supplies	1,939,216
9		(Less):	
10	108, 111	Depreciation & Amortization Reserves	$144,569,083
11	252	Contributions in Aid of Construction	4,395,302
12	**NET BOOK COSTS**		298,370,365
13			
14		**Revenues & Expenses**	
15			
16	400	Operating Revenues	138,935,331
17			
18	**Total Operating Revenues**		138,935,331
19			
20	401-402	Other Operating Expenses	107,326,054
21	403-407	Depreciation & Amortization Expenses	10,956,588
22	408.1	Taxes Other than Income Taxes	13,602,503
23	409-411	Federal & State Income Taxes	(1,194,689)
24			
25	**Total Operating Expenses**		130,690,455
26	**Net Operating Income**		8,244,876
27			
28	415-421.1	Other Income	1,738,600
29	421.2-426.5	Other Deductions	87,502
30	**NET INCOME BEFORE INTEREST EXPENSE**		$9,895,974
31			
32		**Average Customers (Intrastate Only)**	
33		Residential	134,705
34		Commercial	18,805
35		Industrial	384
36		Other	71
37	**TOTAL AVERAGE NUMBER OF CUSTOMERS**		153,965
38			
39		**Other Statistics (Intrastate Only)**	
40		Average Annual Residential Use (Dkt)	92.6
41		Average Annual Residential Cost per (Dkt)	$6.53
42		Average Residential Monthly Bill	$50.39
43			
44		Plant in Service (Gross) per Customer	$2,603

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Absarokee	1,234	453	80		533
2	Amsterdam	727				-
3	Anaconda	9,417	3,371	333		3,704
4	Augusta	284	192	46		238
5	Barber		3			3
6	Belfry	219	5			5
7	Belgrade	5,728	3,117	396		3,513
8	Big Mountain		107	20		127
9	Big Sandy	703	307	78		385
10	Big Sky	1,221				-
11	Big Timber	1,650	852	185		1,037
12	Bigfork	1,421	758	136		894
13	Billings	89,847	9	5	2	16
14	Bonner	1,693	78	4		82
15	Boulder	1,300	469	80		549
16	Bozeman	27,509	13,945	2,101		16,046
17	Browning	3,877	1,063	156		1,219
18	Buffalo		5			5
19	Butte	33,892	12,587	1,379	5	13,971
20	Cardwell	40	17	5		22
21	Carter	62	29	9		38
22	Chester	871	377	128		505
23	Chinook	1,386	736	148		884
24	Choteau	1,802	841	176		1,017
25	Churchill		2			2
26	Clancy	1,406	1,139	80	2	1,221
27	Clinton		348	17		365
28	Columbia Falls	3,645	2,762	307	1	3,070
29	Columbus	1,748	982	153		1,135
30	Conrad	2,753	1,152	220		1,372
31	Coram	337	111	18		129
32	Corvallis	443	782	82		864
33	Cut Bank	3,105	48	17		65
34	Deer Lodge	3,421	1,596	206	1	1,803
35	Dillon	3,752	1,939	345	1	2,285
36	Drummond	318	206	64		270
37	East Glacier	396	122	46		168
38	East Helena	1,642	1,770	107	2	1,879
39	Elliston	225	92	13		105
40	Essex		58	14		72
41	Fairfield	659	399	88		487
42	Florence	901	951	68		1,019
43	Floweree		46	8		54
44	Fort Belknap	1,262	17	12		29
45	Fort Benton	1,594	621	156		777
46	Fort Harrison			59		59
47	Fort Shaw	274	106	12		118
48	Galata		3			3
49	Gallatin Gateway		151	29		180
50	Garneill		9	1		10
51	Garrison	112	24	5		29
52	Gildford	185	79	31		110

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Gransdale		22	2		24
2	Great Falls	56,690	943	50	1	994
3	Greycliff	56	44	5		49
4	Hall		59	14		73
5	Hamilton	3,705	3,321	586		3,907
6	Harlem	848	663	121		784
7	Harlowtown	1,062	535	97		632
8	Havre	9,621	4,546	615		5,161
9	Helena	45,819	14,753	2,132		16,885
10	Hingham	157	90	30		120
11	Hungry Horse	934	257	37		294
12	Inverness	103	41	14		55
13	Jefferson City	295	112	12		124
14	Joplin	210	99	25		124
15	Judith Gap	164	74	15		89
16	Kalispell	14,223	9,203	1,680	1	10,884
17	Kremlin	126	52	16		68
18	Laurel	6,255	10		2	12
19	Ledger		6	1		7
20	Lewistown	6,178	2,848	466		3,314
21	Livingston	7,348	3,647	522		4,169
22	Logan		2			2
23	Lohman		2	1		3
24	Lolo	3,388	1,310	82		1,392
25	Loma	92	39	19		58
26	Manhattan	1,396	1,080	131		1,211
27	Martin City	331	109	16		125
28	Milltown		76	8		84
29	Missoula	57,053	25,366	3,259	1	28,626
30	Moore	186	2	1		3
31	Philipsburg	914	416	70		486
32	Ramsay		36	7		43
33	Red Lodge	2,177	1,503	256		1,759
34	Reedpoint	185	93	16		109
35	Roberts		144	19		163
36	Rocker		8	2		10
37	Rudyard	275	136	32		168
38	Shawmut		25	4		29
39	Shelby	3,216	9	2	2	13
40	Sheridan	659	373	63		436
41	Silver Star		22	5		27
42	Silver Bow		4	2		6
43	Simms	373	159	16		175
44	Somers	556	223	19		242
45	Springdale		2			2
46	Stevensville	1,553	1,320	216		1,536
47	Sun River	131	111	20		131
48	Three Forks	1,728	745	115	3	863
49	Townsend	1,867	1	1		2
50	Trident		2			2
51	Turah		78			78
52	Twin Bridges	400	211	53		264

Sch. 29	Montana Customer Information- Natural Gas, 1/					
	City	Population Census 2000	Residential	Commercial	Industrial & Other	Total
1	Valier	498	303	67		370
2	Vaughn	701	332	24		356
3	Victor	859	439	68		507
4	Warm Springs				1	1
5	West Glacier		107	38		145
6	Whitefish	5,032	2,957	421		3,378
7	Whitehall	1,044	662	111		773
8	Whitlash		2			2
9	Willow Creek	209	95	10		105
10	Williamsburg		1			1
11	Wolf Creek		48	27		75
12	**Total**	451,678	134,714	19,264	25	154,003

1/ Customer populations represent an average of the 12 month period from 01/01/01 through 12/31/01.

Sch. 30	MONTANA EMPLOYEE COUNTS			
	Department	Year Beginning 1/	Year End 1/	Average
1				
2	**Utility Operations**			
3	Executive - 2/		3	
4	Financial, Risk Mgmt. & Information Services - 2/		98	49
5	Human Resources & Administration - 2/		38	19
6	Utility Services & Division Administration	706	665	686
7	Corporate Administration - 2/	140		70
8	Business Development & Regulatory Affairs	18	14	16
9	Transmission	214	188	201
10	Legal - 2/		8	
11	Generation	1		1
12	**Total Utility**	1,079	1,014	1,047
13				
14	**Other Corporate**			
15	Office of the Corporation			
16	**Total Other Corporate**	0	0	0
17	**TOTAL EMPLOYEES**	1,079	1,014	1,047
18				
19	1/ Part time employees have been converted to full time equivalents.			
20				
21	2/ The total number of employees is for The Montana Power Company only. In the past, a portion of			
22	The Montana Power Services Company employees were included in the total. During 2001,			
23	these employees became employees of the utility division of Montana Power.			
24				

Sch. 31	MONTANA CONSTRUCTION BUDGET (ASSIGNED & ALLOCATED)		
	Project Description	Total Company	Total Montana
1			
2	**Electric Operations**		
3			
4	Rainbow-Helena Tower Line Reconductoring	$1,926,600	$1,926,600
5	Hauser 69kV rebuild 10mi	1,100,000	1,100,000
6			
7			
8			
9	All Other Projects < $1 Million Each	37,199,483	37,199,483
10			
11	**Total Electric Utility Construction Budget**	40,226,083	40,226,083
12			
13	**Natural Gas Operations**		
14			
15	Telstad Compressor Station Upgrade	1,100,000	1,100,000
16	North Cobb 16" Loop Line	1,600,000	1,600,000
17			
18	All Other Projects < $1 Million Each	10,629,127	10,629,127
19			
20	**Total Natural Gas Utility Construction Budget**	13,329,127	13,329,127
21			
22	**Common**		
23			
24	All Other Projects < $1 Million Each	1,390,700	1,390,700
25	(Includes Milltown, SAS, AP, Reg Affairs, Carry over)		
26			
27			
28	**Total Common Utility Construction Budget**	1,390,700	1,390,700
29			
30	**Colstrip Unit 4**	1,800,000	1,800,000
31			
32			
33			
34			
35			
36	**Total Colstrip Unit 4 Construction Budget**	1,800,000	1,800,000
37	**TOTAL CONSTRUCTION BUDGET**	$56,745,910	$56,745,910

Sch. 32

TRANSMISSION, DISTRIBUTION and STORAGE SYSTEMS -NATURAL GAS

Transmission System-Sales and Transportation

		Peak Day of Month		Peak Day Volume(Mcf@14.9)		Monthly Volumes(Mcf@14.9)	
	Month	Total Company	Montana	Total Company	Montana	Total Company, 2/	Montana, 3/
1	January					5,271,048	4,396,147
2	February					4,951,693	3,578,051
3	March					3,869,205	3,513,927
4	April		NOT AVAILABLE			3,009,050	3,151,235
5	May					2,105,780	2,534,406
6	June					1,628,883	2,258,357
7	July					1,471,931	2,487,538
8	August					1,773,719	2,313,558
9	September					1,602,209	2,332,309
10	October					3,083,688	2,627,065
11	November					3,496,613	3,329,048
12	December					4,895,298	3,587,274
13	TOTAL					37,159,117	36,108,916
14							
15							

Distribution System-Sales and Transportation

16		Sales Volumes		Transportation Volumes		Monthly Volumes(Mcf@14.9)	
17							
18	Month	Total Company	Montana, 1/	Total Company	Montana, 1/	Total Company, 4/	Montana, 5/
19	January	3,138,331		413,861		3,552,192	3,138,331
20	February	3,007,867		280,319		3,288,186	3,007,867
21	March	2,506,874		264,560		2,771,434	2,506,874
22	April	1,912,904		215,892		2,128,796	1,912,904
23	May	1,128,297		160,958		1,289,255	1,128,297
24	June	708,607		107,691		816,298	708,607
25	July	461,404		84,003		545,407	461,404
26	August	390,324		71,321		461,645	390,324
27	September	430,199		84,380		514,579	430,199
28	October	825,280		92,582		917,862	825,280
29	November	1,562,106		173,230		1,735,336	1,562,106
30	December	2,456,327		199,105		2,655,432	2,456,327
31	TOTAL	18,528,520		2,147,901		20,676,421	18,528,520
32							
33							

Storage System-Sales and Transportation

34		Peak Day & Peak Day Vol.		Total Monthly Volumes(Mcf@14.9)			
35							
36		Total Company	Montana	Total Company 4/		Montana 5/	
37	Month	1/	1/	Injection	Withdrawal	Injection	Withdrawal
38	January			36,696	2,569,160	-	1,007,728
39	February			114	2,508,462	-	1,348,730
40	March			48,553	907,462	-	649,734
41	April			679,435	404,612	14,171	-
42	May			1,648,970	68,275	1,075,294	-
43	June			2,313,529	50,470	992,806	-
44	July			2,522,617	39,583	1,252,234	-
45	August			2,151,610	39,757	935,284	-
46	September			2,119,506	58,162	1,000,025	-
47	October			863,053	377,401	-	142,035
48	November			124,406	813,961	-	624,280
49	December			546	2,042,468	-	943,061
50	TOTAL			12,509,035	9,879,773	5,269,814	4,715,568

51 1/ Data is not accumulated on a daily basis, therefore the peak day and peak day volumes are not available.
52 2/ Includes intrastate and interstate deliveries.
53 3/ Includes intrastate deliveries only.
54 4/ Includes sales and transportation volumes. Losses of gas are not available.
55 5/ Includes sales volumes only. Losses of gas are not available.

Sch. 33	SOURCES OF CORE NATURAL GAS SUPPLY				
	Name of Supplier	Last Year Volumes Mcf	This Year Volumes Mcf	Last Year Avg. Commodity Cost	This Year Avg. Commodity Cost
1					
2	Montana Purchase	6,938,189	6,608,275	$3.5180	$3.6280
3	MP Gas	9,300,643	8,380,845	1.4950	1.5470
4	Stor Trans	657,964	3,100,734	4.9450	4.9660
5	Blaine #3	533,500	616,659	3.3550	5.8980
6	Rosza	713,998	507,181	3.5700	3.5890
7	Carway	314,402	0	2.8970	0.0000
8	**TOTAL CORE SUPPLY**	18,458,696	19,213,694	$2.5363	$3.0080
9					
10					
11					
12					

Sch. 34

MONTANA CONSERVATION & DEMAND SIDE MANAGEMENT PROGRAMS - NATURAL GAS 1/ & 2/

Program Description	Current Year Expenditures	Last Year Expenditures	% Change	Achieved Savings dkt
E+ Free Weatherization 3/	$598,324	$650,471	-8.02%	10,208
E+ Audit Program - Residential	320,236	327,000	-2.07%	12,149
TOTAL	$918,560	$977,471	-6.03%	22,357

1/ NorthWestern LLC administrative costs are included here.

2/ Natural gas USB dollars also fund NorthWestern LLC's 15% Low-Income Discount. Participation in the Discount rose in 2001.

3/ Free Weatherization Program natural gas USB expenditures include gas appliance tune-up, repairs and replacement of condemned appliances, for which no conservation estimates are available.

Sch. 35	MONTANA CONSUMPTION AND REVENUES - NATURAL GAS					
	Operating Revenues 1/		Dkt Sold		Average Customers	
Description	Current Year	Previous Year	Current Year	Previous Year	Current Year	Previous Year
1 Sales of Natural Gas						
2						
3 Residential	$ 81,501,554	$ 69,806,882	12,476,448	12,499,817	134,705	133,082
4 Commercial	38,786,598	30,965,854	5,983,327	5,881,594	18,805	18,437
5 Industrial Firm	2,077,222	3,293,973	235,867	211,421	384	364
6 Public Authorities	216,710	123,664	12,865	10,422	17	13
7 Interdepartmental	301,647	387,754	49,130	47,999	51	80
8 CNG Station	13,105	10,624	1,468	234	-	-
9 Sales to Other Utilities	881,436	662,300	235,600	222,992	3	3
10 TOTAL SALES	123,778,272	105,251,051	18,994,704	18,874,479	153,965	151,979
11	Operating Revenues		Dkt Transported		Average Customers	
12	Current	Previous	Current	Previous	Current	Previous
13	Year	Year	Year	Year	Year	Year
14 Transportation of Gas						
15						
16 Firm - DBU	$ (1,155,454)	$ 1,793,725	2,974,196	3,140,550	205	206
17 Firm - S & TBU	8,530,680	8,182,737	11,338,192	11,459,101	17	20
18						
19 Interruptible - DBU	21,637	83,275	222,817	193,260	11	8
20 Interruptible - S & TBU	883,726	1,207,768	3,743,161	5,242,698	2	2
21 Interruptible - Off System	1,235,384	976,258	8,003,006	3,466,365	17	17
22 Sales Subscriptions						
23						
24						
25						
26						
27						
28 Storage	2,432,834	2,507,240	-	-		
29						
30 **TOTAL TRANSPORTATION**	$ 11,948,807	14,751,003	26,281,372	23,501,974	252	253
31						
32 1/ Does not included unbilled or Canadian Montana Pipeline Corporation revenues.						
33						
34						